

**PUBLIC UTILITIES COMMISSION**

505 VAN NESS AVENUE

SAN FRANCISCO, CA 94102-3298

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May 20, 2022

Agenda ID #20669  
Ratesetting**TO PARTIES OF RECORD IN RULEMAKING 21-10-002:**

This is the proposed decision of Administrative Law Judges Debbie Chiv and Shannon O'Rourke. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's June 23, 2022 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ S. PAT TSEN for

Anne E. Simon

Chief Administrative Law Judge

AES:lil

Attachment

Decision **PROPOSED DECISION OF ALJS CHIV AND O'ROURKE**  
(Mailed 5/20/2022)

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

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

Rulemaking 21-10-002

**DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS  
FOR 2023 - 2025, FLEXIBLE CAPACITY OBLIGATIONS FOR 2023, AND  
REFORM TRACK FRAMEWORK**

## TABLE OF CONTENTS

<u>Title</u>	<u>Page</u>
DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2023 - 2025, FLEXIBLE CAPACITY OBLIGATIONS FOR 2023, AND REFORM TRACK FRAMEWORK .....	1
Summary .....	2
1. Background .....	2
1.1. Procedural History of Phase 2 of the Implementation Track .....	3
1.2. Procedural History of the Reform Track .....	4
2. Issues Before the Commission .....	5
2.1. Scope of Phase 2 of the Implementation Track .....	5
2.2. Scope of the Reform Track .....	6
3. Implementation Track Phase 2 Issues .....	6
3.1. 2023 - 2025 Local Capacity Requirements .....	6
3.1.1. 2023 Final LCR Report .....	9
3.2. 2023 Flexible Capacity Requirements .....	11
3.3. Planning Reserve Margin and Effective Load Carrying Capability Values .....	16
3.3.1. Comments on LOLE and ELCC Study .....	17
3.3.2. Discussion of the Planning Reserve Margin .....	20
3.3.3. Discussion of ELCC Values .....	23
3.4. Qualifying Capacity of Demand Response Resources .....	25
3.4.1. CEC Working Group Report .....	27
3.4.2. Discussion .....	37
3.5. Third-Party Demand Response Testing .....	41
3.5.1. Discussion .....	44
3.6. Qualifying Capacity for Behind-the-Meter Resources .....	45
3.6.1. Joint DER Parties' Proposal .....	47
3.6.2. Parties' Comments .....	50
3.6.3. Discussion .....	54
4. Reform Track Issues .....	55
4.1. SCE's 24-Hour Slice Proposal .....	57
4.2. PG&E's 24-Hour Slice Proposal Modifications .....	60
4.3. Gridwell's Two-Slice Proposal .....	63
4.4. Comments on Structural Proposals .....	65
4.4.1. Comments on the 24-Hour Slice Proposals .....	65
4.4.2. Comments on the Two-Slice Proposal .....	68

## TABLE OF CONTENTS

<u>Title</u>	<u>Page</u>
4.5. Discussion of Structural Proposals.....	72
4.6. Discussion on Elements of the 24-Hour Framework.....	77
4.6.1. Load Forecast Methodology .....	77
4.6.2. Solar and Wind Load Profiles.....	79
4.6.3. Dispatchable Resource Counting.....	81
4.6.4. Energy Storage and Long-Duration Energy Storage Resource Counting .....	82
4.6.5. Hybrid and Co-Located Resource Counting.....	85
4.6.6. Other Resource Counting Methods .....	86
4.6.7. Planning Reserve Margin.....	88
4.6.8. Compliance Penalties.....	90
4.6.9. Coordination with CAISO Processes.....	91
4.6.10. Hourly Load and Resource Trading.....	92
4.6.11. UCAP.....	95
4.6.12. Elimination of the MCC Buckets and Flexible RA Requirements .....	96
4.6.13. Hedging .....	99
4.6.14. Multi-Year Forward Requirements.....	102
4.6.15. 2024 Test Year.....	103
4.7. Process and Schedule for Further Development.....	104
4.7.1. Workstreams .....	104
4.7.2. Schedule for Further Development .....	106
5. Comments on Proposed Decision .....	108
6. Assignment of Proceeding.....	109
Findings of Fact.....	109
Conclusions of Law .....	111
ORDER .....	113

### APPENDIX A - 24-Hour Slice Framework

**DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS  
FOR 2023 - 2025, FLEXIBLE CAPACITY OBLIGATIONS FOR 2023, AND  
REFORM TRACK FRAMEWORK**

**Summary**

This decision adopts local capacity requirements for 2023 - 2025, flexible capacity requirements for 2023, and refinements to the Resource Adequacy program scoped as Phase 2 of the Implementation Track. The decision also adopts Southern California Edison Company's 24-hour slice Reform Track framework, with modifications.

This proceeding remains open.

**1. Background**

On October 7, 2021, the Commission issued the Order Instituting Rulemaking (OIR) to oversee the Resource Adequacy (RA) program, consider program reforms and refinements, and establish forward RA procurement obligations applicable to Commission-jurisdictional load-serving entities (LSEs). This proceeding is the successor to Rulemaking (R.) 19-11-009, which addressed these topics over the preceding two years. Additional information on the procedural history of this proceeding is provided in the OIR.

A Scoping Memo and Ruling (Scoping Memo) for this proceeding was issued on December 2, 2021. The Scoping Memo identified the issues to be addressed in this proceeding, and set forth a schedule and process for addressing those issues. In addition, the Scoping Memo 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. This decision resolves issues scoped as Phase 2 of the Implementation Track and issues scoped as the Reform Track.

### **1.1. Procedural History of Phase 2 of the Implementation Track**

Phase 2 proposals were submitted on January 21, 2022 by: California Independent System Operator (CAISO); California Energy Storage Alliance (CESA), California Solar & Storage Association (CalSSA), Enel X North America, Inc. (Enel X), and Sunrun Inc. (Sunrun) (collectively, Joint Distributed Energy Provider (DER) Parties); Middle River Power LLP (MRP); Pacific Gas and Electric Company (PG&E); and San Diego Gas & Electric Company (SDG&E). The Commission's Energy Division's Phase 2 proposal was filed by an Administrative Law Judge (ALJ) ruling. A workshop on Phase 2 proposals was held on February 4, 2022.

Opening comments on Phase 2 proposals were filed on February 14, 2022 by: Advanced Energy Economy (AEE); CAISO; California Community Choice Association (CalCCA); Calpine Corporation (Calpine); Center for Energy Efficiency and Renewable Technologies (CEERT); California Large Energy Consumers Association (CLECA); California Efficiency + Demand Management Council (CEDMC), Enel X, and Leapfrog Power, Inc. (collectively, Demand Response (DR) Coalition); Green Power Institute (GPI); MRP; OhmConnect Inc. (OhmConnect); PG&E; Southern California Edison Company (SCE); SDG&E; and the Solar Energy Industries Association (SEIA).

Reply comments on Phase 2 proposals were filed on February 24, 2022 by: AEE, CEERT, DR Coalition, Joint DER Parties, MRP, PG&E, and SCE.

On February 18, 2022, an ALJ ruling attached and filed the California Energy Commission's (CEC) Qualifying Capacity of Supply-Side Demand Response Working Group Report and Energy Division's loss of load expectation (LOLE) study. On February 28, 2022, CalCCA and PG&E, jointly as co-leads,

filed the Local Capacity Requirement (LCR) Working Group Report. A workshop on the LOLE study was held on March 3, 2022.

Opening comments on the LCR Working Group Report, CEC Working Group Report, and LOLE study were filed on March 14, 2022 by: American Clean Power – California (ACP-CA), AEE, Alliance for Retail Energy Markets (AReM), CAISO, CalCCA, California Environmental Justice Alliance (CEJA), Calpine, CESA, CLECA, DR Coalition, Independent Energy Producers Association (IEP), MRP, National Resources Defense Council (NRDC), OhmConnect, PG&E, Public Advocates Office (Cal Advocates), REV Renewables, LLC (REV), Southwestern Power Group II, LLC (SWPG) and Pattern Energy Group LP (Pattern), jointly, SCE, SDG&E, San Jose Clean Energy (SJCE), Shell Energy North America (US), L.P. (Shell Energy), Sunrun, Union of Concerned Scientists (UCS), Vistra Corp. (Vistra), and Western Power Trading Forum (WPTF).

Reply comments were filed on March 22, 2022 by: AEE, AReM, CAISO, Cal Advocates, CalCCA, Calpine, California Wind Energy Association (CalWEA), CESA, CLECA, DR Coalition, IEP, MRP, OhmConnect, PG&E, SCE, and WPTF.

## **1.2. Procedural History of the Reform Track**

On February 28, 2022, the Future of Resource Adequacy Working Group Report was submitted by IEP, on behalf of co-facilitators of the Reform Track Working Group.

Opening comments were filed on March 24, 2022 by: ACP; CAISO; Cal Advocates; CalCCA; Calpine; CalWEA; CEDMC; CEERT; CEJA/UCS; Central Coast Community Energy, City and County of San Francisco, San Diego Community Power, Silicon Valley Clean Energy Authority, and Valley Clean

Energy Alliance (collectively, Joint CCAs); CESA; CLECA; Form Energy, Inc. (Form Energy); GPI; Hydrostor, Inc. (Hydrostor); IEP; Long Duration Energy Storage Association of California (LDESC); MRP; NRDC; PG&E; SCE; SDG&E; SEIA and Large-scale Solar Association (LSA); Shell Energy; and WPTF.

Reply comments were filed on April 1, 2022 by: AReM, CAISO, CalCCA, Calpine, CalWEA, CEERT, CESA, CLECA, GPI, Hydrostor, IEP, MRP, NRDC, PG&E, SCE, SDG&E, and SEIA/LSA.

## **2. Issues Before the Commission**

### **2.1. Scope of Phase 2 of the Implementation Track**

The scope of Phase 2 of the Implementation Track, as adopted in the December 2, 2021 Scoping Memo, is summarized below:

1. Adoption of the 2023 - 2025 Local Capacity Requirements (LCR).
  - a. This issue encompasses consideration of how the study's process, parameters, methods, assumptions, and timeline might be improved, including consideration of the LCR Working Group Report, as directed in D.21-06-029.
2. Adoption of the 2023 Flexible Capacity Requirements (FCR).
3. Modifications to the Planning Reserve Margin (PRM). This issue considers modifications to the PRM, including Energy Division's LOLE study.
4. Consider Qualifying Capacity Counting Conventions, including proposals from:
  - a. The CEC Working Group Report, as directed in D.21-06-029;
  - b. The behind-the-meter hybrid Working Group, as discussed in D.21-06-029;



- c. The Supply Side DR Working Group, addressing enhancements to the Load Impact Protocols (LIPs) methodology and process, as directed in D.20-06-031; and
- d. Energy Division's biennial update to the Effective Load Carrying Capability (ELCC) values for wind and solar resources, including development of regional values for wind resources, as directed in D.21-06-029.

## **2.2. Scope of the Reform Track**

The scope of issues in the Reform Track are:

- In D.21-07-014, the Commission established a process and timeline for developing a final restructuring proposal based on PG&E's "slice-of-day" proposal. Parties were directed to undertake a minimum of five workshops to develop implementation details for: (1) Structural Elements; (2) Resource Counting; (3) Need Determination and Allocation; (4) Hedging Component; and (5) Unforced Capacity Evaluation (UCAP) and Multi-Year Requirement Proposals.
- The track encompasses consideration of a final proposed framework and the Workshop Report.

All proposals and comments submitted by parties in Phase 2 and the Reform Track were considered; however, given the large number of parties and volume of comments in this proceeding, some proposals or comments may receive little or no discussion in this decision. Issues within the scope of the proceeding that are not addressed or only partially addressed in this decision may be addressed in a future phase of this proceeding.

## **3. Implementation Track Phase 2 Issues**

### **3.1. 2023 - 2025 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 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.<sup>1</sup> CAISO conducts an annual LCR study and the Commission resets local procurement obligations each year after a review and approval of CAISO’s recommendations. A series of subsequent decisions (most recently in D.21-06-029) established local procurement obligations for 2008 through 2024. 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 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 Corporation (NERC), the Western Electricity Coordinating Council (WECC), and CAISO.<sup>2</sup>

In D.20-06-031, the Commission expressed concern that CAISO’s updated reliability criteria had not been fully vetted by the Commission and directed a working group to evaluate CAISO’s updated criteria and other LCR related

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<sup>1</sup> D.06-06-064 at 17.

<sup>2</sup> CAISO Notice of Availability, 2021 Final Local Capacity Technical Study, May 1, 2020, at Section 1.5.

issues.<sup>3</sup> With little progress made through the initial working group, in D.21-06-029, the Commission recommended that PG&E and CalCCA co-lead the LCR Working Group to evaluate and make recommendations on the following issues:<sup>4</sup>

- (1) Potential modifications to the current LCR timeline or processes to allow more meaningful vetting of LCR study results;
- (2) Inclusion of energy storage limits in the LCR report and its implications on future resource procurement; and
- (3) How best to harmonize the Commission's and CAISO's local resource accounting rules.

On February 28, 2022, PG&E and CalCCA submitted the LCR Working Group Report. The Working Group Report provided an overview from CAISO about the LCR stakeholder process, the interplay between the LCR process and the Transmission Planning Process (TPP), the factors that influenced the increases to the Greater Bay Area LCR, and changes to the LCR criteria. The Working Group Report also provided an overview of how the LCR study process evaluates the need to sufficiently charge storage in local areas. The LCR Working Group Report did not put forth any recommendations.<sup>5</sup>

In comments, CalCCA recommends coordination between the Commission's Integrated Resource Plan (IRP) process and CAISO's TPP processes to address questions, including where new resources should be located to be more effective, and what are the transmission alternatives and costs compared to a large increase in LCR or a new resource at a more effective

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<sup>3</sup> D.20-06-031 at 8.

<sup>4</sup> D.21-06-029 at Ordering Paragraph (OP) 5.

<sup>5</sup> LCR Working Group Report at Attachment 1-10.

location.<sup>6</sup> CEJA, CESA, and PG&E support this coordination.<sup>7</sup> CAISO, CalCCA, and MRP suggest the Commission and CAISO coordinate to provide notice of CAISO's stakeholder process to the service list in the RA proceeding.<sup>8</sup> MRP recommends the Commission take no further action on modifications to the LCR criteria other than participating in CAISO's LCR stakeholder process.

The Commission appreciates the effort put forth by the LCR Working Group. We acknowledge that it has been two years since D.20-06-031 established the LCR Working Group and that no recommendations to modify the LCR criteria or process have come to light. Without any proposals to consider, the Commission determines that no further action to modify the LCR criteria is necessary at this time. Parties are encouraged to participate in CAISO's LCR stakeholder process to address potential changes. We request that Energy Division and CAISO coordinate to ensure that information about CAISO's stakeholder process is noticed to the service list in the RA proceeding.

### **3.1.1. 2023 Final LCR Report**

CAISO's Draft 2023 LCR Report was received on April 7, 2022. No comments on the Draft LCR Report were filed. CAISO's 2023 Final LCR Report was submitted on April 29, 2022. No comments on the Final LCR Report were filed.

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<sup>6</sup> CAISO Comments on LCR Report, March 14, 2022, at 16.

<sup>7</sup> CEJA Reply Comments on LCR Report, March 22, 2022, at 3; CESA Comments on LCR Report, March 14, 2022, at 19; PG&E Comments on LCR Report, March 14, 2022, at 2.

<sup>8</sup> CAISO Comments on LCR Report, March 14, 2022, at 11; CalCCA Comments on LCR Report, March 14, 2022, at 18; MRP Comments on LCR Report, March 14, 2022, at 5.

The CAISO's recommended 2023 - 2025 LCR values are summarized in the following table, with the recommended 2022 - 2024 LCR values provided for comparison.

<b>2023 - 2025 Local Capacity Requirements</b>			
<b>Local Area Name</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>
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.			

2022 - 2024 Local Capacity Requirements			
Local Area Name	2022	2023	2024
Humboldt	111	115	120
North Coast/North Bay	834*	834*	834*
Sierra	1220*	1338*	1455*
Stockton	562*	562*	562*
Greater Bay	7231*	7418*	7605*
Greater Fresno	1987*	2069*	2151*
Kern	356*	375*	394*
Big Creek/Ventura	2173	935	951
LA Basin	6646	6196	6251
San Diego/Imperial Valley	3993	3540	3330
Total	25113	23382	23653
* 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 2023 – 2025 to be reasonable. Accordingly, CAISO’s recommended 2023 – 2025 LCR values set forth in the table above are adopted.

### 3.2. 2023 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.”<sup>9</sup>

<sup>9</sup> D.13-06-024 at 2.

This year, on April 7, 2022, CAISO notified the Commission that both the draft and final Flexible Capacity Needs Assessment for 2023 (Final FCR Report) would be delayed and that the Final FCR Report would not be filed until mid-May. On April 28, 2022, an ALJ's ruling was issued that shortened the time for comments on the Final FCR Report and removed reply comments from the schedule. 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, 2022. No Comments on the Final FCR Report were filed by CEDMC and CPower, jointly, on May 19, 2022. The Final FCR Report contains the following figures for 2023, with the 2022 FCR figures provided for comparison.

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

2022 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	19,140	18,532	7,393	10,212	927
February	19,584	18,742	7,477	10,328	937
March	19,362	18,694	7,458	10,301	935
April	19,527	18,853	7,521	10,389	943
May	20,180	19,378	9,613	8,796	969
June	17,318	16,552	8,211	7,513	828
July	16,648	15,924	7,900	7,228	796
August	16,956	16,198	8,036	7,352	810
September	17,030	16,453	8,162	7,468	823
October	19,707	18,912	7,545	10,421	946
November	19,300	18,740	7,476	10,327	937
December	19,819	19,321	7,708	10,647	966

CAISO maintains a must-offer obligation (MOO) 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 Qualifying Capacity (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. Currently, the CAISO AAHs and RA measurement hours are 4:00-9:00 PM year-round. 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 2022 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 2023 to 2025, it is necessary to introduce a spring season for the months of March and April and that since the peak spring hours are shifting later in the day, the spring AAH should be 5:00–10:00 PM.<sup>10</sup> CAISO recommends that the AAH for winter and summer months (January to February and June to December) should remain 4:00-9:00 PM for 2023.

CEDMC/CPower state that the MCC buckets should be revised to reflect the CAISO's updated AAHs for March and April.<sup>11</sup> They also suggest that the DR bucket should be adjusted to apply to all months, rather than only May through September, and Saturday availability should not be required for the DR Bucket and buckets 1-3 since the AAHs do not include Saturday.

CEDMC/CPower state that updates to the DR Bucket should be delayed until 2024 since load impact evaluations for 2023 have been submitted and providers have executed contracts for 2023 delivery based on the current AAHs.

In light of the brief review period available for the Final FCR Report, the Commission finds that the FCR 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 the spring months of March and April to be reasonable and adopts the same revised hours for the RA measurement hours. This modification ensures that the

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<sup>10</sup> CAISO Final Flexible Capacity Needs Assessment for 2023, May 17, 2022, at 27-30.

<sup>11</sup> CEDMC/CPower Comments on CAISO FCR Report, May 19, 2022, at 2.

Commission's measurement hours remain aligned with the CAISO's AAHs. Accordingly, the RA measurement hours shall be 5:00-10:00 PM for March and April, and 4:00-9:00 PM for all other months beginning in the 2023 RA compliance year.

MCC bucket categories 1, 2, and 3 are based on the existing measurement hours of 4:00-9:00 PM. As such, it is also necessary to adjust the hours for MCC buckets 1, 2, and 3 to reflect the new revised measurement hours. Accordingly, 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 Monday - Saturday, 4 consecutive hours between 4 PM and 9 PM, and at least 24 hours per month from May - September.	8.3%
1	Monday - Saturday, at least 100 hours per month. For the month of February, total availability is at least 96 hours. January - February, May - December, 4 consecutive hours between 4 PM - 9 PM. March - April, 4 consecutive hours between 5 PM - 10 PM.	17.0%
2	Every Monday - Saturday. January - February, May - December, 8 consecutive hours that include 4 PM - 9 PM. March-April, 8 consecutive hours that include 5 PM - 10 PM.	24.9%
3	Every Monday - Saturday. January-February, May - December, 16 consecutive hours that include 4 PM - 9 PM. March-April, 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)

### **3.3. Planning Reserve Margin and Effective Load Carrying Capability Values**

In D.20-06-031, the Commission stated that given the extensive changes to the grid and the mix of generating resources since the PRM was established in D.04-01-050, it is appropriate to review the PRM through an LOLE study performed by Energy Division.<sup>12</sup> In D.21-06-029, the Commission adopted a biennial schedule for updates to ELCC values for wind and solar resources and stated that the first update would occur in 2022 for the 2023 RA year, with subsequent updates occurring in every even year.<sup>13</sup> Energy Division was also directed to develop regional ELCC values for wind resources for consideration.<sup>14</sup>

On February 18, 2022, Energy Division's LOLE and ELCC Study (LOLE study) was submitted into the proceeding. The LOLE study presents results for the 2024 RA year in order to align with the Reform Track timeline and to allow time for consideration of the results and modifications to LSE positions prior to potential implementation.<sup>15</sup> For purposes of the study, Energy Division assumed a high penetration of variable and use-limited resources and removed Diablo Canyon and some cogeneration resources from the system in order to surface LOLE events and test the reliability contribution of different resource types through an ELCC study.<sup>16</sup> While the portfolio may not be entirely consistent with assumptions of past reliability modeling, such as the CEC's recent mid-term reliability analysis, Energy Division notes that its results are generally consistent.

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<sup>12</sup> D.20-06-031 at 21, OP 9.

<sup>13</sup> D.21-06-029 at OP 14.

<sup>14</sup> *Id.* at OP 15.

<sup>15</sup> Energy Division LOLE Study at 2.

<sup>16</sup> *Id.*

The study's results were provided at the monthly level to mirror the current monthly RA construct, in contrast to the annual results presented in other studies, including in the IRP proceeding.

The LOLE study results indicate that a 19 to 21 percent PRM is needed in the peak months (July through September) when utilizing the study's ELCC results for solar, wind, hybrid, and storage resources. These results do not include a forced outage derate for thermal resources (or UCAP). Accounting for forced outages through UCAP results in a PRM reduction of 2.5 to 4.5 percent depending on the month. For peak months, the UCAP PRM is 16 to 17 percent.

In addition, Energy Division's study reports ELCC values across a range of scenarios, given the rapidly changing portfolio of the generator fleet and uncertainty about when and how many new resources will come online.<sup>17</sup> The base scenario includes the existing fleet plus all resources reported in LSE IRP plans and additional capacity selected in the RESOLVE capacity expansion modeling conducted in the IRP proceeding. Alternate scenarios for 2024 include cases with no new online capacity, and with all or half of the resources from LSE IRP plans (Scenarios A-C). A portfolio meant to represent the 2023 fleet (Scenario D) is also included.

### **3.3.1. Comments on LOLE and ELCC Study**

Numerous parties raise concerns about the inputs and assumptions used in the LOLE model, including AReM, CAISO, CalCCA, Cal Advocates, CalWEA, CESA, Pattern, PG&E, SCE, and SJCE.<sup>18</sup> Parties seek additional information or

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<sup>17</sup> Energy Division LOLE Study at 23.

<sup>18</sup> AReM Comments on LOLE Study, March 14, 2022, at 3; CAISO Comments on LOLE Study, March 14, 2022, at 6; Cal Advocates Comments on LOLE Study, March 14, 2022, at 3; CalCCA Comments on LOLE Study, March 14, 2022, at 5; CalWEA Comments on LOLE Study, March 14, 2022, at 3; CESA Reply Comments on LOLE Study, March 22, 2022, at 3; Pattern

*Footnote continued on next page.*

adjustments to the model prior to implementation, with key concerns including: the composition of the base portfolio (particularly, the use of resources selected by the RESOLVE capacity expansion model in the IRP proceeding), the lack of recent weather data in the model, and the limit of imports to 4,000 megawatts (MW) during peak hours.<sup>19</sup> CAISO, IEP, and UCS express confusion regarding the Modified Delta method and its application in allocating the diversity benefit to each resource type to arrive at resource ELCC values.<sup>20</sup> MRP and SCE question the choice to remove nuclear and combined heat and power units to surface loss of load, and note that when units are removed on a monthly basis, the resulting annual LOLE sums to 0.16, rather than the standard reliability target of 0.1.<sup>21</sup>

Multiple parties, such as AReM, Calpine, CalCCA, NRDC, PG&E, REV, SCE, and SDG&E, voice concerns over the study's compatibility with the slice-of-day framework and the Commission's decisions in R.20-11-003, the OIR to Ensure Reliable Electric Service in the Event of an Extreme Weather Event

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Comments on LOLE Study, March 14, 2022, at 2; PG&E Comments on LOLE Study, March 14, at 3; SCE Comments on LOLE Study, March 14, 2022, at 3; SJCE Comments on LOLE Study, March 14, 2022, at 1.

<sup>19</sup> See, e.g., AReM Comments on LOLE Study, March 14, 2022, at 5; CAISO Comments on LOLE Study, March 14, 2022, at 10; Cal Advocates Comments on LOLE Study, March 14, 2022, at 8, 11, 16; Cal Advocates Reply Comments on LOLE Study, March 22, 2022, at 4; CalCCA Comments on LOLE Study, March 14, 2022, at 5; IEP Comments on LOLE Study, March 14, 2022, at 2; MRP Comments on LOLE Study, March 14, 2022, at 3; NRDC Comments on LOLE Study, March 14, 2022, at 3; Pattern Comments on LOLE Study, March 14, 2022, at 2; PG&E Comments LOLE Study, March 14, 2022, at 4; UCS Comments on LOLE Study, March 14, 2022, at 6; WPTF Comments on LOLE Study, March 14, 2022, at 4.

<sup>20</sup> CAISO Comments on LOLE Study, March 14, 2022, at 8; IEP Comments on LOLE Study, March 14, 2022, at 5; UCS Comments on LOLE Study, March 14, 2022, at 1.

<sup>21</sup> MRP Comments on LOLE Study, March 14, 2022, at 2; SCE Comments on LOLE Study, March 14, 2022, at 7.

(Summer Reliability proceeding).<sup>22</sup> AReM and PG&E advocate for considering modifications to the PRM after a decision on the Reform Track framework.<sup>23</sup>

AReM remarks that changes to the PRM are not necessary for 2023 because the Commission already addressed 2023 via the effective PRM adopted in the Summer Reliability proceeding. CalCCA states that the Commission should demonstrate that the total net qualifying capacity (NQC) of resources available in the market will cover the MWs needed to meet a new PRM.<sup>24</sup>

CESA notes that Energy Division only partially complied with D.21-06-029 as the analysis fails to provide increased granularity for the ELCC values of variable energy resources (VERs).<sup>25</sup> PG&E and SCE comment that the only changes that should be adopted for 2023 are granular ELCC values for wind resources, and Vistra and Pattern support regional wind ELCCs.<sup>26</sup>

Several parties support increasing the PRM and updating ELCC values for 2023, including Calpine, IEP, MRP, Shell Energy, and WPTF.<sup>27</sup> CAISO states that

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<sup>22</sup> AReM Comments on LOLE Study, March 14, 2022, at 6; CalCCA Comments on LOLE Study, March 14, 2022, at 8; Calpine Comments on LOLE Study, March 14, 2022, at 4; NRDC Comments on LOLE Study, March 14, 2022, at 2; PG&E Comments on LOLE Study, March 14, 2022, at 3; REV Comments on LOLE Study, March 14, 2022, at 4; SCE Comments on LOLE Study, March 14, 2022, at 2; SDG&E Comments on LOLE Study, March 14, 2022, at 1.

<sup>23</sup> AReM Reply Comments on LOLE Study, March 22, 2022, at 3; PG&E Reply Comments on LOLE Study, March 22, 2022, at 2.

<sup>24</sup> CalCCA Reply Comments on LOLE Study, March 22, 2022, at 3.

<sup>25</sup> CESA Comments on LOLE Study, March 14, 2022, at 4.

<sup>26</sup> PG&E Reply Comments on LOLE Study, March 22, 2022, at 3; SCE Reply Comments on LOLE Study, March 22, 2022, at 2; Pattern Comments on LOLE Study, March 14, 2022, at 3; Vistra Comments on LOLE Study, March 14, 2022, at 3.

<sup>27</sup> Calpine Reply Comments on LOLE Study, March 22, 2022, at 1; IEP Reply Comments on LOLE Study, March 22, 2022, at 2; MRP Reply Comments on LOLE Study, March 22, 2022, at 2; Shell Energy Reply Comments on LOLE Study, March 22, 2022, at 3; WPTF Reply Comments on LOLE Study, March 22, 2022, at 3.

establishing the appropriate PRM is critical to maintaining a safe, reliable grid and reducing reliance on non-RA or contingency measures.<sup>28</sup> IEP reasons that the current ELCC values are outdated and continued reliance on the values could threaten reliability for 2023.<sup>29</sup> IEP states that the LOLE study demonstrates the pressing need to adopt a higher PRM and that a PRM of 20 - 21 percent for 2023 is reasonable. MRP contends that the PRM must be modified as the supply mix has changed profoundly in the 17 years since the RA program began and the initial PRM has yet to be reexamined.<sup>30</sup> MRP supports a 21 percent PRM for 2023, consistent with the study, if the associated ELCC values are also adopted; if ELCC is not adopted for storage and hybrid, a 28 percent PRM would be appropriate.

### **3.3.2. Discussion of the Planning Reserve Margin**

In D.04-01-050, the Commission first adopted the requirement that LSEs procure system RA capacity based on an LSE's share of the monthly peak load plus a PRM of 15 to 17 percent.<sup>31</sup> While the Commission has considered revising the PRM in the intervening years,<sup>32</sup> the PRM adopted in D.04-01-050 has yet to be modified. In D.21-12-015, issued in the Summer Reliability proceeding, the Commission adopted an "effective PRM" of 20 to 22.5 percent for summers 2022 and 2023.<sup>33</sup>

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<sup>28</sup> CAISO Reply Comments on LOLE Study, March 22, 2022, at 1.

<sup>29</sup> IEP Reply Comments on LOLE Study, March 22, 2022, at 1.

<sup>30</sup> MRP Comments on LOLE Study, March 14, 2022, at 1, 4.

<sup>31</sup> D.04-01-050 at 11.

<sup>32</sup> See e.g., R.08-04-012, OIR to Consider Revisions to the Planning Reserve Margin for Reliable and Cost-Effective Electric Service.

<sup>33</sup> D.21-12-015 at OP 3.

The Commission concurs with multiple parties that further vetting of the modeling inputs and assumptions in Energy Division's LOLE study is necessary. As part of the IRP process, the same model is currently being updated by Energy Division and the Commission anticipates that these updates may include several of parties' recommendations, including incorporation of the most recent load forecast and weather data. A reliability study using that modeling tool is currently planned to inform the IRP proceeding and is anticipated to cover a planning horizon to 2030 and potentially beyond. Energy Division should consider inclusion of a near-term year, such as 2024, in that modeling effort. We encourage parties to engage in the vetting process in the IRP proceeding, including participating in the Modeling Advisory Group. We also believe parties may benefit from further education on Energy Division's modeling methods and recommend that Energy Division engage in more stakeholder process regarding its modeling methods.

The Commission agrees with parties that support increasing the PRM for 2023. While we recognize that additional modeling on the LOLE study should be undertaken, we agree with CAISO and other parties that state that the LOLE study results directionally support the effective PRM adopted in the Summer Reliability proceeding and demonstrate the urgent need for a higher PRM in 2023.

As noted in D.21-12-015, the acceleration of climate change has resulted in more frequent and intense extreme weather events across the West in the form of severe heat events, droughts, and wildfires.<sup>34</sup> Moreover, the composition of the generator fleet has changed significantly over the past ten years and continues to

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<sup>34</sup> D.21-12-029 at 5, 14.



rapidly evolve with the growth of energy storage and an aging thermal fleet. For these reasons, and as indicated by the LOLE study, failure to adopt an increased PRM may undermine grid reliability.

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.

A 16 percent PRM for 2023 does not change the contingency resource target of 2,000 to 3,000 MWs that the investor-owned utilities (IOU) were directed to procure for summer 2023 in D.21-12-015. Rather, IOUs will continue to target the same MW totals for contingency resources, despite the change in LSE RA requirements. We note, however, that D.21-12-015 provided that “[o]nly costs associated with RA resources in excess of an IOU’s own 15% PRM should be charged to all benefiting customers in the IOU’s service territory via the Cost Allocation Mechanism.”<sup>35</sup> Based on the revised PRM adopted in this decision, Ordering Paragraph 70 of D.21-12-015 shall be modified to reflect that only costs associated with RA resources in excess of an IOU’s own PRM, as adopted in the RA program, should be charged to all benefiting customers in the IOU’s service territory via the Cost Allocation Mechanism (CAM).

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<sup>35</sup> D.21-12-015 at OP 70.

We note 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.

### **3.3.3. Discussion of ELCC Values**

The current ELCC values for solar and wind were adopted in 2019 (for implementation in 2020) and have been in place for three years. Particularly given the rapid growth of solar, storage, and wind resources, we agree with parties that it is necessary to update the ELCC values for 2023 to more accurately account for resources' reliability contribution. The Commission finds that the ELCC values in Scenario D are the best representation of resources likely to be online for 2023 because Scenario D is based on the IRP's 2023 Preferred System Plan (PSP) while the base scenario and Scenarios A-C are based on the 2024 PSP. Therefore, we find Scenario D's values to be appropriate to apply to solar and wind resources beginning in the 2023 RA year.<sup>36</sup> Accordingly, Scenario D's ELCC values are adopted, as follows:

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<sup>36</sup> Energy Division LOLE Study at 26.

2023 ELCC Values		
Month	Solar	Wind
January	0.4%	21.9%
February	3.0%	23.4%
March	3.5%	20.7%
April	4.4%	20.7%
May	6.4%	21.8%
June	13.1%	18.2%
July	14.4%	16.6%
August	12.4%	13.8%
September	11.1%	14.2%
October	7.4%	12.6%
November	5.7%	16.5%
December	3.5%	20.5%

In addition, the Commission agrees with parties that regional ELCC values for wind should be considered, as directed in D.21-06-029; however, Energy Division has yet to issue its regional wind ELCC values. Energy Division is requested to submit the results into the proceeding as soon as practicable. After parties have an opportunity to comment on the results, the Commission endeavors to adopt regional wind values for the 2023 RA year.

Although updated ELCC values for solar and wind are adopted in this decision, the Commission is not persuaded to expand ELCC values to storage and hybrid resources at this time. In light of the adoption of a new RA framework in the Reform Track, expanding the use of the ELCC methodology to additional resources on a temporary basis is not prudent and may create unnecessary market confusion. As such, for hybrid and storage resources, the

current QC methodologies will remain in place unless superseded by another decision.

### **3.4. Qualifying Capacity of Demand Response Resources**

In D.21-06-029, the Commission discussed CAISO's initiation of proposed revision request (PRR) 1280 to its Business Practice Manual. The Commission stated that:

The revision would reject any non-net neutral credits that lower an RA requirement without the resource being shown on a CAISO Supply Plan. Implementation of PRR 1280 would effectively mean that DR credits allocated to LSEs by the Commission would no longer be accepted by CAISO. PRR 1280 was held in abeyance until August 1, 2021 to provide time for CAISO and the Commission to work collaboratively to resolve RA issues.<sup>37</sup>

In a prior RA rulemaking, R.19-11-009, CAISO maintained that because credited DR resources administered by IOUs are not shown on CAISO Supply Plans and are not subject to CAISO tariff provisions, these resources do not allow CAISO to meet reliability needs and are not subject to RAIM charges if they fail to perform.<sup>38</sup> CAISO initially proposed an 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. The current QC value of DR resources is based on LIPs, which is informed and adjusted by historic DR performance.

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<sup>37</sup> D.21-06-029 at 27. CAISO subsequently withdrew PRR 1280 on August 30, 2021. See <http://www.aiso.com/Documents/ProposedRevisionRequest1280WithdrawalCall091321.html>.

<sup>38</sup> D.21-06-029 at 27.

In D.21-06-029, the Commission declined to adopt an ELCC methodology for DR counting and determined that “implementing a new interim ELCC approach for 2022 is rife with uncertainties and unanswered questions that must be addressed.”<sup>39</sup> The Commission added:

We also see validity in Joint DR Parties’ comment that the E3 ELCC study was intended to be conceptual, and that the proposed methodology represents an abrupt change from the longstanding use of the LIP process, which is currently underway and evaluates the historic performance of DR resources on an *ex post* basis using robust analysis. We find that ELCC has not at this point been proven to be superior to LIPs or any other methodology at this time for DR. Further, the Commission cannot adopt a study or methodology that has not been thoroughly reviewed.<sup>40</sup>

Rather, the Commission adopted a working group process led by the CEC to develop a DR QC counting methodology.<sup>41</sup> We requested that the CEC develop recommendations for a comprehensive and consistent measurement and verification (M&V) 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 launch a working group in the 2021 Integrated Energy Policy Report (IEPR) and make recommendations on the following issues:

- (1) Whether CAISO’s ELCC proposal is reasonable and appropriate to determine DR QC and/or what modifications, if any, should be considered;

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<sup>39</sup> *Id.* at 37.

<sup>40</sup> *Id.*

<sup>41</sup> *Id.* at OP 11.

- (2) Whether the LIP + ELCC proposal is reasonable and appropriate to determine DR QC and/or what modifications, if any, should be considered;
- (3) Whether other proposals that may be presented in the CEC's stakeholder process are reasonable and appropriate to determine DR QC;
- (4) Whether and to what extent alignment of DR M&V methods in the operational space for CAISO market settlement purposes with methods to determine RA QC in the planning space should be achieved, and if so, how;
- (5) 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;
- (6) Whether implementation of any elements of DR QC methodology modifications that might be adopted by the Commission should be phased in over time; and
- (7) Whether, and if so how, any changes to DR adders should be reflected in DR QC methodology.<sup>42</sup>

The CEC was requested to submit recommendations for implementation for the 2023 RA compliance year.

#### **3.4.1. CEC Working Group Report**

The CEC submitted the Qualifying Capacity of Supply-Side Demand Response Working Group Report (CEC Report) on February 18, 2022. The CEC Report notes that there was insufficient time to develop a permanent QC methodology for the 2023 RA year and that stakeholders asserted that the Working Group should await the outcome of the Reform Track process before making a recommendation.<sup>43</sup> The CEC Report submits interim

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<sup>42</sup> *Id.*

<sup>43</sup> CEC Report at 34.

recommendations for the 2023 RA year but notes that a consensus was not reached on the proposed methodologies. The CEC Report discusses three proposed interim approaches, and other recommendations, summarized below.

#### **3.4.1.1. LIP-informed ELCC Proposal**

PG&E and SCE propose using the LIP analysis to inform the QC of the ELCC methodology, referred to as LIP-informed ELCC.<sup>44</sup> The methodology is said to apply the same logic and principles as bid-informed ELCC but use LIP profiles as the input for the ELCC model. The proposal assumes Commission Staff would calculate the ELCC values in the SERVM model.

For the ELCC calculations, the proposal would require Commission Staff to develop hourly availability profiles for DR programs using either a larger period of historical weather conditions (*e.g.*, 20 years) or a set of representative days. After collecting various inputs from DR providers (DRPs), calculations would be run on: (1) the aggregate portfolio of ELCC of all intermittent and energy-limited resources, (2) “First-in” ELCC for each resource class, (3) “Last-in” ELCC for each resource class, (4) “First-in” ELCC for each DR program, and (5) “Last-in” ELCC for each DR program.<sup>45</sup> Then, the “Portfolio ELCC” would be allocated to each resource class using “interactive effects” and the “Last-in ELCC” value to calculate a final ELCC value.

The CEC Staff recommends that for the 2023 RA year, the proposal should be adopted on an interim basis for IOU resources. The CEC Staff notes that due to time constraints, it is unlikely Energy Division Staff can perform the modeling

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<sup>44</sup> See *id.* at 35.

<sup>45</sup> DR ELCC Guide: Using LIP-Informed Profiles to Calculate DR ELCC in SERVM, at 7; available at: <https://efiling.energy.ca.gov/GetDocument.aspx?tn=241246&DocumentContentId=75092>.

for third-party DRPs as well. The CEC Staff remarks that the proposal “meets the principles stated by the California ISO and adopting this method should better reflect contribution of DR to reliability.”<sup>46</sup> The CEC Staff recognizes that the proposal requires an additional step of developing LIP profiles as an input to the ELCC model, which may create technical and timing challenges for implementation.

CAISO, PG&E and SCE support the proposal as an interim approach for the 2023 RA year.<sup>47</sup> CAISO states that if this proposal is adopted, CAISO would support an exemption from RAAIM charges. CAISO states that it is working with Energy and Environmental Economics (E3) and IOUs to develop implementation details. SCE supports the proposal as an interim solution but maintains that running SERVM to calculate components is time-consuming and not transparent to IOUs and third-party DRPs. PG&E recognizes that the proposal would require more load impact data than currently required for LIPs, making it difficult to implement for 2023. OhmConnect asserts that the proposal addresses gaps in bid-informed ELCC, including using LIP *ex ante* projections as the input in ELCC modeling, which allows a DR provider to forecast changes in customer growth.<sup>48</sup> OhmConnect suggests that the methodology should be available to third-party DRPs, as well as IOUs.

CLECA and SDG&E oppose the proposal and generally state that there is insufficient detail and transparency about the data inputs, such as when the

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<sup>46</sup> CEC Report at 36.

<sup>47</sup> CAISO Comments on CEC Report, March 14, 2022, at 1; PG&E Comments on CEC Report, March 14, 2022, at 2; SCE Comments on CEC Report, March 14, 2022, at 2.

<sup>48</sup> OhmConnect Comments on CEC Report, March 14, 2022, at 6.



ELCC results and hourly load impacts would be provided.<sup>49</sup> SDG&E highlights concerns with the use of E3's ELCC modeling, which SDG&E claims produced very low QC values without transparency about the inputs and assumptions used. CLECA asserts that there is insufficient time to validate results and implement the proposal for 2023, especially because Energy Division has never performed this modeling. CLECA also comments that the proposal runs counter to D.21-06-029 in which the Commission stated it cannot adopt a methodology that has not been thoroughly reviewed. DR Coalition and SDG&E assert that stakeholders have yet to see the results of this approach and that the results should be evaluated to determine whether the proposal is superior to LIPs.<sup>50</sup> CESA expresses concern about the lack of granularity of the ELCC modeling to recognize individual attributes, as well as the feasibility of annual ELCC modeling, which is necessary to ensure DR portfolios are accurately valued.<sup>51</sup>

#### **3.4.1.2. Incentive-Based Proposal**

CEDMC proposes an incentive-based approach modeled in part by approaches used by the PJM Interconnection and the New York Independent System Operator.<sup>52</sup> On a quarterly basis, DRPs would estimate the capability of their resources and claim a corresponding QC value using any proprietary analytical tool. DRPs would submit claimed QC values and supporting documentation to Energy Division for review, after which Energy Division

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<sup>49</sup> CLECA Comments on CEC Report, March 14, 2022, at 3; SDG&E Comments on CEC Report, March 14, 2022, at 2.

<sup>50</sup> SDG&E Comments on CEC Report, March 14, 2022, at 13; DR Coalition Comments on CEC Report, March 14, 2022, at 15.

<sup>51</sup> CESA Comments on CEC Report, March 14, 2022, at 15.

<sup>52</sup> CEC Report at 36.

would determine the approved amount.<sup>53</sup> Each DR provider would provide a \$2,500/MW-year collateral payment to Energy Division to be held in escrow based on the amount of NQC contracted. A resource's performance would be evaluated against the provider's monthly supply plan to determine underperformance. A financial penalty structure would be based on PG&E's Capacity Bidding Program (CBP), where penalties are issued if providers deliver less than 75 percent of the contracted amount.

The CEC Staff recommends the proposal be adopted on an interim basis for third-party DRPs for the 2023 RA year.<sup>54</sup> The CEC Staff states that the proposal uses the same counting method for *ex post* evaluation as the LIP process uses for *ex ante* QC valuation, which the CEC deems to be a rough estimate of reliability contribution. However, the CEC Staff asserts that the proposed penalty structure may be insufficient to ensure performance for DR because a provider only incurs a penalty if delivering less than 75 percent of the contracted amount. The CEC Staff recommends a penalty structure based on PG&E's CBP structure and the Demand Response Auction Mechanism (DRAM) penalty structure, where penalties would be triggered if a DR resource performs below 90 percent of contracted capacity.

CESA, DR Coalition, and OhmConnect support CEDMC's proposal as an interim solution.<sup>55</sup> DR Coalition claims the proposal is much simpler than the current LIP process and other proposals but criticizes the modified penalty

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<sup>53</sup> CEDMC Interim DR Qualifying Capacity Methodology Proposal, at 4, available at: <https://efiling.energy.ca.gov/GetDocument.aspx?tn=241266&DocumentContentId=75112>.

<sup>54</sup> CEC Report at 37.

<sup>55</sup> CESA Reply Comments on CEC Report, March 22, 2022, at 7; DR Coalition Comments on CEC Report, March 14, 2022, at 5; OhmConnect Comments on CEC Report, March 14, 2022, at 7.

structure because the CEC does not explain why the CBP structure is ineffective for third-party DR but effective for IOU CBP programs. CESA states that the proposal offers more flexibility for different types of DR and an incentive to accurately claim capacity and thus, should be less burdensome on the Commission to validate claimed capacity.

Several parties oppose the proposal, including Cal Advocates, CAISO, PG&E, and SCE,<sup>56</sup> and take issue with the penalty structure. Cal Advocates points out that the proposal compares performance to month-ahead supply plans, not year-ahead, and does not compare performance between monthly and yearly supply plans, which would require replacing capacity shortfalls. Cal Advocates believes the penalties fail to improve the accuracy of calculated DR values as there is no incentive to accurately bid in months that a DRP is not required to dispatch. CAISO observes the penalties to be very low compared to recent average system RA prices and recommends an analysis on whether the penalty structure provides sufficient incentives to reasonably estimate QC values. PG&E contends that the proposal assesses a higher penalty for higher performance because the penalty is tied to demonstrated capacity rather than undelivered contracted capacity. SCE adds that the proposal requires a process to hold funds in escrow and deduct penalties, which may result in implementation challenges.

CAISO expresses concern that the proposal allows a DRP to calculate QC values with limited upfront validation. SCE comments that using any proprietary tool to estimate QC may result in wide variability across IOUs and

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<sup>56</sup> Cal Advocates Comments on CEC Report, March 14, 2022, at 24; CAISO Comments on CEC Report, March 14, 2022, at 5; PG&E Comments on CEC Report, March 14, 2022, at 3; SCE Comments on CEC Report, March 14, 2022, at 4.

third-party DRPs. PG&E and Cal Advocates posit that the proposal is overly burdensome on Energy Division Staff because it requires Staff to evaluate DRPs' capacity self-assessments on a quarterly basis and to request justifications for claimed capacity when the information is already submitted in the LIP process. Cal Advocates argues that Staff would be required to master a large number of new, non-standard forecasting models in a short period of time, whereas LIP is based on standard, well-understood statistical methods.

**3.4.1.3. Loss of Load Probability  
(LOLP)-weighted LIP Proposal**

CLECA proposes to use relative LOLP as hourly weights to apply to the LIPs (rather than using a simple average), referred to as the LOLP-weighted LIP proposal.<sup>57</sup> The proposal recognizes the difference in contribution to reliability of load impacts in different hours by weighting those impacts by the relative likelihood of loss of load events. The reliability model will run multiple scenarios for load (based upon historical weather patterns) and resource availability, and will yield the unserved energy for each scenario.<sup>58</sup> For each hour of each month, the LOLP is calculated by dividing the number of unserved energy events that occurred in that hour by the total number of model runs. To develop the proposed weights, LOLP would be converted to a relative hourly LOLE by summing the LOLP for a particular hour across all months and dividing by the total LOLP for the year. Summing across all months should address concerns that loss of load events can occur in any summer month, even if

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<sup>57</sup> CEC Report at 38.

<sup>58</sup> CLECA Alternative LIP + LOLE Approach Proposal, at 1, available at: <https://efiling.energy.ca.gov/GetDocument.aspx?tn=241485&DocumentContentId=75442>.

the LOLE study predicts that unserved energy events will be concentrated in one or two months.

CLECA elaborates that a load reduction at 7:00–8:00 PM will have a higher weight than a 4:00–5:00 PM load reduction, reflecting the concern about serving net peak load.<sup>59</sup> CLECA believes the proposal offers transparency as to how a DR program’s hourly load impacts are valued: if capacity values significantly change after applying LOLE weights, it would be due to hourly impacts not occurring during hours when a program is most needed.

CLECA maintains that the only outstanding issue is the source of the hourly LOLE.<sup>60</sup> CLECA voices concern that Energy Division’s recent LOLE study for 2024 indicates highest expected unserved energy from 9:00–10:00 PM (rather than 7:00–8:00 PM) and some DR programs were not designed to meet needs past 9:00 PM. If DR programs are needed at or after 9:00 PM, CLECA states that DR program design should have an opportunity for modification. Rather, CLECA advocates for use of the CEC’s LOLE results for 2023, which shows a majority of the LOLE between 4:00–9:00 PM. Alternatively, CLECA supports use of CAISO’s E3 ELCC study for 2020 where a majority of LOLE also occurs between 4:00–9:00 PM.

The CEC Staff recommends that for the 2023 RA year, the LOLP-weighted LIP proposal should be adopted as an interim back-up option for third-party DRPs and IOUs.<sup>61</sup> The CEC Staff observes the proposal to be an incremental improvement to reflecting contribution to reliability relative to unweighted LIP results.

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<sup>59</sup> CLECA Comments on CEC Report, March 14, 2022, at 8.

<sup>60</sup> *Id.* at 11.

<sup>61</sup> CEC Report at 38.

CAISO, CESA, and DR Coalition support the LOLP-weighted LIP proposal as an interim solution for 2023.<sup>62</sup> DR Coalition claims the proposal provides a more transparent and simple approach to addressing CAISO's concerns but does not address all concerns about the LIP process. CAISO advocates that IOUs use CLECA's proposal as an interim option if LIP-informed ELCC cannot be implemented for 2023 and recommends the proposal for DRPs in lieu of CEDMC's proposal or the status quo. CAISO urges the proposal is an improvement over the LIP process because LOLE weighting captures a DR program's estimated capability in more critical hours and will not likely pose significant implementation barriers for 2023.

PG&E recommends the Working Group develop the proposal as a potential long-term solution but argues that it is not robust enough for an interim solution, as it does not account for differences in CAISO's and the Commission's valuations for 2023.<sup>63</sup> SCE states that the proposal does not evaluate contribution to grid reliability in the context of other types of capacity on the grid, such as wind, solar, and storage, and does not consider the order through which individual DR resources are dispatched or their interactive effects.<sup>64</sup>

#### **3.4.1.4. CEC Recommendations**

In summary, the CEC Report recommends on an interim basis for 2023: the LIP-informed ELCC for IOU resources, the incentive-based approach for third-party DRPs, the LOLP-weighted LIPs as a back-up option for IOUs and

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<sup>62</sup> CAISO Comments on CEC Report, March 14, 2022, at 3; CESA Reply Comments on CEC Report, March 22, 2022, at 7; DR Coalition Comments on CEC Report, March 14, 2022, at 16.

<sup>63</sup> PG&E Comments on CEC Report, March 14, 2022, at 4.

<sup>64</sup> SCE Comments on CEC Report, March 14, 2022, at 4.

third-party DRPs, and the status quo LIP methodology.<sup>65</sup> The CEC Report recommends the Commission request CAISO grant a RAAIM exemption for DR resources that choose to use LIP-informed ELCC and the Commission direct IOUs to move DR portfolios onto CAISO Supply Plans. The CEC Report recommends the Commission extend the Working Group process beyond the February 2022 Working Group Report to develop long-term recommendations beginning with the 2024 RA year.

Several parties favor extending the CEC Working Group process to develop a long-term solution, including CAISO, CESA, DR Coalition, OhmConnect, PG&E, and SDG&E.<sup>66</sup> DR Coalition and OhmConnect urge that the Working Group Report be submitted with sufficient time for a Commission decision before the annual LIP process in December. DR Coalition and CESA comment that it does not make sense to develop a long-term DR QC methodology until the Reform Track framework is developed, as ELCC may no longer be applicable.

Several parties support optionality of the interim solutions for third-party DRPs and IOUs, including CESA, CLECA, DR Coalition, OhmConnect, SCE, and SDG&E.<sup>67</sup> CESA notes that the Commission is not required to adopt a methodology for 2023, as D.21-06-029 only requests the CEC submit

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<sup>65</sup> CEC Report at 39.

<sup>66</sup> CAISO Comments on CEC Report, March 14, 2022, at 6; CESA Comments on CEC Report, March 14, 2022, at 18; DR Coalition Comments on CEC Report, March 14, 2022, at 6; OhmConnect Comments on CEC Report, March 14, 2022, at 2; PG&E Comments on CEC Report, March 14, 2022, at 1; SDG&E Comments on CEC Report, March 14, 2022, at 13.

<sup>67</sup> CESA Comments on CEC Report, March 14, 2022, at 15; CLECA Comments on CEC Report, March 14, 2022, at 4; DR Coalition Comments on CEC Report, March 14, 2022, at 17; OhmConnect Comments on CEC Report, March 14, 2022, at 3; SCE Comments on CEC Report, March 14, 2022, at 1; SDG&E Comments on CEC Report, March 14, 2022, at 13.

recommendations for consideration. CAISO recommends that the LIP-informed ELCC proposal be adopted for both the 2023 and 2024 RA years to refine the methodology with more data.<sup>68</sup>

Cal Advocates opposes optionality because applying four under-developed standards for IOUs and third-party DRPs is arbitrary, makes it difficult to compare capacity contributions, contravenes the Commission's finding that IOU DR and third-party DR programs "should be on a level playing field," and has potential impacts that have not been explored in the CEC Report.<sup>69</sup> Cal Advocates reasons that there is insufficient time to implement four methodologies for the 2023 RA year and that the status quo should be maintained to avoid potential negative implications.

#### **3.4.2. Discussion**

The Commission recognizes the extensive effort undertaken by the CEC Staff and participating parties over several months to submit proposals for interim QC valuation methodologies for DR resources.

To implement a new QC methodology for DR resources for the 2023 RA year, even on an interim basis, the Commission observes significant timing and resource constraints for the proposed methodologies. The ELCC-informed proposal requires Energy Division Staff to undertake new ELCC modeling that has not been done before, including developing hourly availability profiles for all DR programs, gathering numerous data inputs from DRPs, and running several complex calculations. The process does not contemplate an opportunity for validation and review of the final results by stakeholders or the Commission.

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<sup>68</sup> CAISO Comments on CEC Report, March 14, 2022, at 6.

<sup>69</sup> Cal Advocates Comments on CEC Report, March 14, 2022, at 20 (citing D.16-09-056, Finding of Fact 56).



The incentive-based proposal requires Energy Division Staff to review and approve DRPs' self-assessment of capacity on a quarterly basis and potentially seek data from DRPs to validate claimed capacity values. As DRPs may estimate their claimed capacity on any proprietary analytical tool, Energy Division Staff would be required to comprehend many new, unfamiliar methodologies within a short timeframe. The proposal appears to require other Commission processes to be in place, such as a means to hold funds in escrow and deduct penalties.

The LOLP-weighted LIP proposal raises fewer resource and timing constraints from a Commission Staff perspective, as it relies on a completed LOLE study. In addition, the LIP process for the 2023 RA year can proceed as it currently does since the results would still be used as part of the LOLP-weighted LIP proposal.

Regarding the LIP-informed ELCC proposal, the Commission agrees with concerns about the lack of transparency regarding the modeling process and that the results of the modeling are yet to be reviewed. As the Commission observed in D.21-06-029, "ELCC has not at this point been proven to be superior to LIPs or any other methodology at this time for DR. The Commission cannot adopt a study or methodology that has not been thoroughly reviewed."<sup>70</sup> With the incentive-based proposal, the proposal has not been sufficiently developed to ensure that the penalty structure provides necessary incentives for DRPs to reasonably estimate QC values. We are also concerned that the use of any analytical tool by DRPs may lead to wide variability of capacity values.

The LOLP-weighted LIP proposal is a simpler, more transparent methodology that does not require time-intensive or costly modeling of the

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<sup>70</sup> D.21-06-029 at 37.

reliability impacts of DR programs. We agree with parties that favor the proposal as an improvement over the current LIP process because LOLE weighting reflects DR resources' approximate capability during the most critical hours. As such, the Commission deems the LOLP-weighted LIP methodology to be a reasonable interim QC methodology for IOU and third-party DR resources.

To select a LOLE study as the basis for the methodology, CLECA recommends use of the CEC or CAISO's LOLE study, noting that Energy Division's LOLE study revealed highest expected unserved energy from 9:00-10:00 PM when some DR programs are not designed to meet needs after 9:00 PM. This discrepancy between unserved energy events and DR program hours suggests that DR program hours may need to be revisited for future RA years. However, given parties' concerns regarding the portfolio used in Energy Division's LOLE model, we find it appropriate to consider other modeling results for 2023 or 2024.

The CEC's LOLE study for the 2023 RA year, provided in the CEC's September 2021 Midterm Reliability Analysis Staff Report,<sup>71</sup> appears to be an appropriate source for the LOLP-weighted LIP methodology. However, the Commission has not yet had an opportunity to vet the underlying data in the CEC's study results. The Commission intends to obtain the data underlying the CEC's LOLE study for consideration in this proceeding. Once the Commission evaluates this data and parties have an opportunity to comment, we will consider whether the LOLP-weighted LIP proposal should be adopted as an interim methodology for IOU and third-party DR resources. Should a future

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<sup>71</sup> See CEC Midterm Reliability Analysis, September 30, 2021, at 11, available at: <https://www.energy.ca.gov/sites/default/files/2021-09/CEC-200-2021-009.pdf>.

decision adopt the LOLP-weighted LIP proposal for the 2023 RA year, the decision will be issued by August 2022 in order to be timely implemented.

The Commission finds insufficient record to adopt a DR QC counting proposal for the 2023 RA year at this time. Consequently, the status quo LIP methodology will remain in effect unless superseded by a future decision.

The Commission agrees that the CEC Working Group should continue to develop long-term recommendations, consistent with the adopted Reform Track framework. We are aware of the timing and coordination concerns with the CEC Working Group process and the Commission's process for adopting a new counting methodology. To adopt a new DR QC methodology for the 2024 RA year, in advance of the LIP process that begins in December, a Working Group recommendation would need to be submitted by August 2022. Given the short time remaining, it is unlikely that the Working Group will have sufficient time to develop an implementable proposal for 2024, and more realistic to submit recommendations for the 2025 RA year and beyond. Thus, the Commission requests that the CEC Working Group develop recommendations that consider the following issues for 2025 RA year:

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

The Commission requests that the CEC Working Group submit recommendations into this proceeding by February 1, 2023.

### **3.5. Third-Party Demand Response Testing**

In D.20-06-031, the Commission required that:

Third-party demand response (DR) resources, procured by non-investor-owned utility load-serving entities, be subject to the following testing requirements:

- (a) The DR resource must dispatch for four consecutive hours during the Resource Adequacy measurement hours in every quarter of the delivery year.
- (b) The test must be done at the resource ID level and all resources within the same sub-Load Aggregation Point [LAP] must be dispatched concurrently.<sup>72</sup>

Energy Division put forth a proposal to modify the testing requirements adopted in D.20-06-031.<sup>73</sup> First, Energy Division proposes expanding the testing requirement to third-party DR resources procured by any LSE, not just non-IOU LSEs, in order to “maintain a level playing field in the [RA] market between the IOUs and Non-IOU LSEs.”<sup>74</sup>

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<sup>72</sup> D.20-06-031 at OP 13.

<sup>73</sup> Energy Division Phase 2 Proposal, January 21, 2022, at 1.

<sup>74</sup> *Id.*

Second, Energy Division states that while testing is required once per quarter, the decision did not specify which month in the quarter to conduct testing and often, the monthly QC values aggregated across the resource IDs in a sub-LAP differ month to month in the same quarter. Energy Division proposes that DRPs must conduct the test in the month with the highest aggregate QC for each sub-LAP, as this will alleviate the need to conduct tests for different months with varying QCs. Lastly, D.20-06-031 required that all resources must be dispatched for four consecutive hours and that performance must be averaged over the four consecutive hours. Energy Division recommends clarifying that the testing results must be submitted to Energy Division in an hourly format.

PG&E supports expanding testing requirements to all LSEs to ensure a level playing field in the RA market.<sup>75</sup> DR Coalition supports the clarifications to the testing month and reporting requirements.<sup>76</sup> SCE seeks clarification as to which conditions the third-party testing requirements would apply to IOU tariffed third-party DR programs, such as in the Base Interruptible Program (BIP) where third-party resources are typically dispatched only for grid emergencies.<sup>77</sup> If third-party resources are dispatched every quarter, this could decrease participation in the program and result in loss of critical MWs during emergency periods.

SCE adds that there are DR contracts approved by the Commission before the RA period of 4:00–9:00 PM was adopted.<sup>78</sup> SCE recommends exempting from third-party DR testing: existing legacy reliability DR resources (RDRR), proxy

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<sup>75</sup> PG&E Comments on Phase 2, February 14, 2022, at 11.

<sup>76</sup> DR Coalition Comments on Phase 2, February 14, 2022, at 10.

<sup>77</sup> SCE Comments on Phase 2, February 14, 2022, at 4.

<sup>78</sup> *Id.* at 5.

DRs that are dispatched less than 50 percent of their maximum tariff or contract provisions, and DR contracts executed and approved before the effective date of the decision. DR Coalition supports this with regard to legacy RDRR and pre-existing Commission-approved contracts.<sup>79</sup>

DR Coalition states that before expanding DR testing requirements, the Commission should first adopt criteria as to what is a “stable” and “new and changing” DR resource should be adopted, and how a resource can graduate to or be demoted from a tier.<sup>80</sup> DR Coalition proposes that the unit of analysis should be done at the DR provider portfolio level, and that for Tier 1, an average performance of 75 percent and above the aggregate monthly supply plan capacity should constitute as “good performance,” which is the threshold for PG&E’s CBP payment structure. For Tier 2, graduation or demotion should be based on performance over a two-test period.

CLECA supports occasional tests to validate DR performance but states that increased test frequency makes DR participation less attractive.<sup>81</sup> CLECA notes that each test incurs a financial loss and that the load reduction involves shutting down an industrial process or commercial activity. CLECA recommends clarification that customers participating through a DR aggregator for IOU programs are not subject to the quarterly test requirement. The proposal should also be modified to include a reduction in testing over time based on a successful track record.

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<sup>79</sup> DR Coalition Reply Comments on Phase 2, February 24, 2022, at 4.

<sup>80</sup> DR Coalition Comments on Phase 2, February 14, 2022, at 10.

<sup>81</sup> CLECA Comments on Phase 2, February 14, 2022, at 10.

### 3.5.1. Discussion

The Commission agrees that applying third-party DR testing requirements to resources under contract with both IOU and non-IOU LSEs establishes consistency in testing requirements and maintains a level playing field in the RA market. Thus, we find Energy Division's proposal to be reasonable. We also agree with SCE's recommendations regarding certain exemptions to these testing requirements. We clarify that the testing requirements do not apply to:

(1) third-party DR resources procured via IOU programs, such as CBP and BIP, or contracted by an IOU under Commission-approved contracts prior to the effective date of this decision; and (2) third-party DR resources in the 2023 DRAM pilot, as these Commission-approved programs already have defined dispatch and testing requirements.

Accordingly, third-party DR resources procured by all LSEs shall be subject to the following testing requirements:

- (a) The DR resource must dispatch for four consecutive hours during the Resource Adequacy measurement hours in every quarter of the delivery year.
- (b) The test must be done at the resource ID level and all resources within the same sub-LAP must be dispatched concurrently. If QC values vary by month, within each quarter, then the test shall be done in the month with the highest QC for each sub-LAP.

The testing requirements shall not apply to: (1) third-party DR resources procured via IOU programs, such as CBP and BIP, or contracted by an IOU under Commission-approved contracts prior to the effective date of this decision; and (2) third-party DR resources in the 2023 DRAM pilot. The testing requirements for third-party DR resources procured by any LSE shall be effective beginning in the 2023 RA compliance year.

Next, the Commission agrees that Energy Division's proposal that DRPs must conduct the test in the month with the highest aggregate QC for each sub-LAP is reasonable and we adopt it here. We also find it appropriate that the testing results submission requirements described in D.20-06-031 must include testing results in an hourly format.

Lastly, when tiered testing was adopted in D.20-06-031, the Commission determined that "there is insufficient record to determine criteria to differentiate between 'new and changing resources' and those with established track records" but the Commission encouraged parties to "propose criteria for what constitutes a stable resource and a sufficient track record to qualify for reduced testing requirements . . . ." <sup>82</sup> With respect to DR Coalition's proposal, there is inadequate data to evaluate the performance determination, as proposed. Thus far, the Commission has only received partial data from two DRPs to which the testing requirement applied in 2021. There is also insufficient record support on this proposal. The Commission finds it premature to modify the technical aspects of the requirement at this time and will revisit the testing tiers as more data becomes available.

### **3.6. Qualifying Capacity for Behind-the-Meter Resources**

In D.20-06-031, the Commission considered a proposal to give behind-the-meter (BTM) solar-plus-storage (hybrid) resources a QC value equivalent to in-front-of-the-meter (IFOM) resources.<sup>83</sup> The Commission determined that eight issues must be addressed before considering treating BTM resources similarly to IFOM resources:

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<sup>82</sup> D.20-06-031 at 40.

<sup>83</sup> *Id.* at 29.



- (1) Forward determination of capacity associated with renewable production, consumption, charging, and export;
- (2) RA requirements associated with customers providing capacity;
- (3) Wholesale market participation including metering, dispatch control, and communication with CAISO;
- (4) Cost for energy associated with consumption, charging, and export;
- (5) Changes such that net energy metering (NEM) and self-generation incentive program (SGIP) resources are compensated for capacity, while discounting for their NEM and SGIP compensation as necessary to ensure that the resources do not receive compensation beyond their value;
- (6) Load forecasting and adjustment for BTM resources;
- (7) Interaction of such resources with existing BTM resources such as proxy DR; and
- (8) Deliverability determination.

The following year, in D.21-06-029, the Commission considered a proposal to create a “market-informed pathway” for BTM standalone storage to receive RA capacity value for exports to the grid by applying the QC methodology for IFOM hybrid resources.<sup>84</sup> The Commission rejected the proposal as premature, stating that “a capacity value should be determined after the underlying issues are addressed and after the Commission has determined that BTM resources will be providing incremental, reliable capacity benefits.”<sup>85</sup> We further stated that, unlike an IFOM resource, a BTM storage resource connecting to the grid via Rule 21 does not undergo a deliverability study, which means that BTM exports are not guaranteed to deliver when resources are needed most. Thus, BTM and

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<sup>84</sup> D.21-06-029 at 50.

<sup>85</sup> *Id.* at 54.

IFOM resources have different behaviors and “should not be counted equivalently.” The Commission concluded that a working group could develop a future proposal and “reiterate[d] that a viable proposal must address the eight issues previously enumerated in D.20-06-031, as well as the concerns raised in D.15-11-042 . . . .”<sup>86</sup>

### **3.6.1. Joint DER Parties’ Proposal**

Joint DER Parties submitted a lengthy proposal in Phase 2, which was then significantly revised in reply comments. We endeavor to summarize the primary points here.

Joint DER Parties claim that the Commission did not explicitly direct for the eight issues in D.20-06-031 to be fully resolved, and that only three items (QC valuation method, incrementality rules, and must-offer obligations) are under the Commission’s jurisdiction and within the scope of the proceeding. The parties argue that the three items must first be addressed before addressing the other barriers.<sup>87</sup>

Joint DER Parties recommend a QC methodology that accounts for BTM resources’ ability to export to the grid and propose that the QC value should initially be equivalent to the methodology for IFOM resources.<sup>88</sup> In reply comments, the parties recommend that a resource’s QC should be based on its contracted capacity.<sup>89</sup> A resource’s contract would cover the availability requirement, whether four hours or a subset of hours in a future framework. Joint DER Parties state that the contract-based method could be used for IFOM

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<sup>86</sup> *Id.* at 55.

<sup>87</sup> Joint DER Parties Reply Comments on Phase 2, February 24, 2022, at 3.

<sup>88</sup> Joint DER Parties Phase 2 Proposal, January 21, 2022, at 10.

<sup>89</sup> Joint DER Parties Reply Comments on Phase 2, February 24, 2022, at 7.

systems that commit resources for capacity deliveries less than the QC counting method or can facilitate multiple-use applications.

Joint DER Parties initially proposed that IOUs use the same submetering protocol as for the Emergency Load Reduction Program.<sup>90</sup> In reply comments, the parties recommend that retail capacity settlement be based on the meter generator output (MGO) methodology, the current measurement and settlement method for storage-backed DR resources.<sup>91</sup> The revised proposal suggests the MGO methodology be modified to not zero out exports or zero out lookback intervals when storage is charging. The parties suggest the details of submetering, data management, and settlement be addressed in a later phase.

To account for exports beyond load reductions, the parties recommend CAISO expand its existing model for market-integrated system RA under the Proxy Demand Response (PDR) model to allow for BTM resources to provide RA.<sup>92</sup> They urge that the Commission and CAISO should coordinate to establish a QC value and MOO and for CAISO to adopt an appropriate DER aggregation (DERA) deliverability methodology. Once DERAs that participate through the DER provider (DERP) model are awarded eligibility, the Commission and CAISO could apply the same operational requirements as resources that currently participate through PDR (*i.e.*, MOO for periods when resources are needed most). In reply comments, Joint DER Parties make further revisions, such as that RA resources participating through DERP adhere to any requirements applicable under the slice-of-day framework, that the Commission

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<sup>90</sup> Joint DER Parties Phase 2 Proposal, January 21, 2022, at 29.

<sup>91</sup> Joint DER Parties Reply Comments on Phase 2, February 24, 2022, at 9.

<sup>92</sup> Joint DER Parties Phase 2 Proposal, January 21, 2022, at 19.

amend its Rule 24/32 tariffs to account for DERA participation, and that charging and discharging settlements use retail rates in the near term.<sup>93</sup>

For deliverability, Joint DER Parties propose that CAISO and the Commission develop a new model that identifies necessary distribution upgrades to accommodate export deliverability based on LSE interest and/or procurement needs, and allocates costs associated with deliverability-related distribution upgrades to participants and developers through a \$/kW fee.<sup>94</sup> Distribution Generation Deliverability could then be assigned to BTM resources that LSEs either contract for or commit to provide RA capacity.

Regarding incrementality, Joint DER Parties contend that because SGIP payments are incentives for technology equipment, not services, customers with BTM resources that receive technology incentives can receive compensation for services. Joint DER Parties initially proposed that for net-metered customers, the QC would be the same for standalone storage and no renewable production be considered; this section was removed from the revised proposal.<sup>95</sup> Joint DER Parties advocate for a new NEM tariff that allows for wholesale market participation.<sup>96</sup>

Joint DER Parties suggest eliminating some of the barriers established in D.20-06-031 to enable progress, such as removing the interaction of resources with existing BTM resources and load forecasting and adjustments.<sup>97</sup> The parties

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<sup>93</sup> Joint DER Parties Reply Comments on Phase 2, February 24, 2022, at 17, 55.

<sup>94</sup> Joint DER Parties Phase 2 Proposal, January 21, 2022, at 59.

<sup>95</sup> Joint DER Parties Phase 2 Proposal, January 21, 2022, at 41; Joint DER Parties Reply Comments on Phase 2, February 24, 2022, at 11.

<sup>96</sup> Joint DER Parties Phase 2 Proposal, January 21, 2022, at 73.

<sup>97</sup> *Id.* at 7.

recommend modifying other barriers, such as deleting “wholesale market participation, including metering, dispatch control, and communication with CAISO” to focus on submetering for retail capacity settlement and visibility at the transmission distribution interface. The proposal also recommends deleting the double-compensation issue for NEM and SGIP resources and focusing on “RA incrementality framework for services and NEM.”<sup>98</sup>

### **3.6.2. Parties’ Comments**

Because portions of the initial proposal were significantly revised in reply comments, parties did not have an opportunity to comment on the revised proposal. Below is a summary of parties’ comments to the initial proposal.

AEE, SEIA, and CEERT support the initial proposal and believe it reasonably addresses the eight barriers identified in D.21-06-029.<sup>99</sup> These parties generally maintain that if the barriers to allowing BTM participation in the RA program are not resolved, investment in BTM resources will not be made, resulting in a less functional resource that is detrimental to grid reliability, investors, and ratepayers. AEE opines that enabling BTM resources to participate in RA is consistent with the direction and goals of Federal Energy Regulatory Commission (FERC) Order No. 2222, which requires wholesale market operators to allow DER aggregations to access wholesale markets and provide services they are capable of providing. AEE and SEIA generally argue that the Commission can take the step of adopting a QC method, CAISO can concurrently revise its approach to assess deliverability, and the CEC can

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<sup>98</sup> *Id.* at 42.

<sup>99</sup> AEE Comments on Phase 2, February 14, 2022, at 5; CEERT Comments on Phase 2, February 14, 2022, at 2; SEIA Comments on Phase 2, February 14, 2022, at 3.

concurrently categorize RA-eligible, CAISO market-integrated BTM resources as supply-side resources.

Several parties oppose the initial proposal, including Calpine, MRP, PG&E, SCE, and SDG&E.<sup>100</sup> These parties generally criticize the proposal as premature because the threshold issues identified in D.20-06-031 must be resolved prior to granting BTM resource RA capacity value. SCE and Calpine express concern that rushing to award a QC value without resolving the identified issues will be problematic for reliability. PG&E suggests the working group explore existing BTM resources that are able to provide proxy RA value through load reductions before undertaking further efforts on this issue. SCE, PG&E, and MRP recommend deferring action on the proposal until the Commission implements a new RA reform framework, as any valuation method may change under a new framework.

Calpine, SCE, SDG&E, and PG&E raise concerns that the proposal does not adequately address double-counting or double-compensation concerns.<sup>101</sup> These parties generally state that because SGIP, NEM, and DR are included in existing load forecasts to determine RA requirements, the same resource should not be treated as incremental RA, which can also impact reliability. SCE comments that to ensure DERs are not double-counted under DERP, DERs participating in a DERA may not participate in more than one DERA, may not participate in the CAISO market separately from the DERA, and may not participate in a retail

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<sup>100</sup> Calpine Comments on Phase 2, February 14, 2022, at 1; MRP Reply Comments on Phase 2, February 24, 2022, at 4; PG&E Comments on Phase 2, February 14, 2022, at 1; SCE Comments on Phase 2, February 14, 2022, at 7; SDG&E Comments on Phase 2, February 14, 2022, at 2.

<sup>101</sup> Calpine Comments on Phase 2, February 14, 2022, at 1; SCE Comments on Phase 2, February 14, 2022, at 11; SDG&E Comments on Phase 2, February 14, 2022, at 2; PG&E Comments on Phase 2, February 14, 2022, at 2.

NEM program that does not allow wholesale market participation. PG&E questions whether BTM resources on time-of-use (TOU) rates should receive additional compensation for their expected performance since there is already an incentive to dispatch during peak hours.

In response to Joint DER Parties citing FERC Order No. 2222 to support the contention that metering, dispatch, and telemetry are no longer barriers to DERA wholesale participation, CAISO replies that statements made in Order No. 2222 were specific to that filing, not a broad statement about distribution visibility, metering, and telemetry for RA.<sup>102</sup> In addition, CAISO points out that Order No. 2222 is pending FERC review. CAISO emphasizes that BTM resources counted as RA must adhere to requirements applicable to other RA resources, including a 24 x 7 MOO; CAISO visibility through telemetry and metering; CAISO operational control to fully dispatch; and energy settlement and performance requirements. CAISO states that the wholesale market integration issues outlined in D.20-06-031 are key factors that CAISO relies on to maintain reliability.

CAISO disagrees that the proposal only fails to address one key issue in settlement. CAISO posits that because wholesale rates are significantly lower than retail rates, BTM resources are not likely to respond to meet CAISO's reliability needs. For example, resources will likely discharge according to a retail signal to avoid demand charges rather than exposure to wholesale prices. The proposal thus limits incentives for a resource to follow CAISO dispatches and limits the resource's effectiveness in meeting CAISO reliability needs.

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<sup>102</sup> CAISO Comments on Phase 2, February 14, 2022, at 6.

CAISO also asserts that the proposal raises discrimination issues as the Federal Powers Act establishes that no resource receive undue preference by requiring correct wholesale economic dispatch based on market and grid conditions. Allowing BTM resources to participate under DERAs to avoid CAISO's locational marginal price (LMP)-based settlement may be discriminatory because it gives BTM resources an advantage over resources subject to wholesale rates.

SCE and PG&E state that potential revisions to the Rule 21 criteria should be addressed in the Rule 21 interconnection proceeding, and SCE notes that any modifications to deliverability requirements must be addressed by CAISO.<sup>103</sup> SDG&E opposes creating a new model for identifying distribution upgrades, as the existing Distribution Planning Process already identifies upgrades to accommodate forecast export capacity and identifying upgrades based on "LSE interest" or "procurement needs" do not provide sufficient certainty or specificity for planning.<sup>104</sup>

PG&E reasons that if DERP is the pathway to value DERs, it is unclear why PDRs should be modified to allow the same benefits; additionally, only one product should be modified because the same resource cannot toggle between the two models.<sup>105</sup> SDG&E opposes BTM resources participating as PDRs because PDR was created for DR resources and serious reliability concerns would arise if other resources operated as PDR resources do.<sup>106</sup>

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<sup>103</sup> SCE Comments on Phase 2, February 14, 2022, at 9; PG&E Comments on Phase 2, February 14, 2022, at 6.

<sup>104</sup> SDG&E Comments on Phase 2, February 14, 2022, at 12.

<sup>105</sup> PG&E Comments on Phase 2, February 14, 2022, at 6.

<sup>106</sup> SDG&E Comments on Phase 2, February 14, 2022, at 6.



### 3.6.3. Discussion

The Commission recognizes that the threshold barriers identified in D.20-06-031 are complex issues that require coordination across several Commission proceedings and CAISO stakeholder initiatives. We acknowledge Joint DER Parties' efforts to address some of these challenges. However, we agree with concerns raised by some parties that the proposal is premature and fails to address the threshold issues the Commission identified in D.20-06-031.

The Commission is not persuaded that exporting BTM resources should be permitted to participate similarly as CAISO's PDR resources because PDRs were created specifically for DR resources, which lack the direct control and communication infrastructure to allow the resource to be available in the real-time market. Moreover, given the existing incentive structure under NEM and TOU, the Commission should ensure that any additional compensation is awarded strictly for incremental performance.

The Commission remains concerned about the lack of visibility and availability of BTM resources for dispatch in CAISO markets. Deliverability also remains a key concern given that BTM resources connecting through Rule 21 do not undergo a deliverability study and there is no guarantee that exports are deliverable during peak times. These are particularly important issues given the projected higher levels of BTM resource penetration.

As the Commission stated in D.21-06-029, "a capacity value should be determined after the underlying issues are addressed and after the Commission has determined that BTM resources will be providing incremental, reliable capacity benefits. The Commission cannot assess the capacity value of a product

that has not yet been defined.”<sup>107</sup> The Commission reiterates its direction in D.20-06-031 and D.21-06-029: that critical threshold issues must be addressed first before the Commission can consider providing a capacity value to BTM resources. Any future proposal must explicitly address these specific barriers.

#### **4. Reform Track Issues**

In D.21-07-014, the Commission outlined the history of the current RA framework that was first implemented in 2006, and the recent trends and concerns that have arisen, which has led to the Commission’s reexamination of the RA program to ensure that the framework can provide grid reliability at all times of the day.<sup>108</sup> The Commission established five key principles that encompass concerns with the current framework and the objectives of the RA program, as set forth in Public Utilities (Pub. Util.) Code Section 380. The principles are as follows:<sup>109</sup>

- Principle 1: To balance ensuring a reliable electrical grid with minimizing costs to customers.
- Principle 2: To balance addressing hourly energy sufficiency for reliable operations with advancing California’s environmental goals.
- Principle 3: To balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity and transactability.
- Principle 4: To be implementable in the near-term (*e.g.*, 2024).
- Principle 5: To be durable and adaptable to a changing electric grid.

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<sup>107</sup> D.21-06-029 at 54.

<sup>108</sup> See D.21-07-014 at 5-7.

<sup>109</sup> Further detail on each of these principles can be found in D.21-07-014 at 25-28.

The Commission stated that a final proposal should also consider compatibility with existing Commission planning goals and programs, such as the IRP and Renewable Portfolio Standard (RPS) proceedings.

In D.21-07-014, the Commission considered several proposals to restructure the RA program and determined that PG&E's slice-of-day proposal best addressed the principles and concerns with the current framework and was best positioned to be implemented for the 2024 RA year, if further developed.<sup>110</sup> Parties were directed to undertake a minimum of five workshops to develop implementation details for a final restructuring proposal based on PG&E's slice-of-day proposal. Workshops would cover the following issues:<sup>111</sup>

- (1) Structural Elements;
- (2) Resource Counting;
- (3) Need Determination and Allocation;
- (4) Hedging Component; and
- (5) Unforced Capacity Evaluation and Multi-Year Requirement Proposals.

Workshops were also directed to cover the transactability of RA products, multi-day reliability event concerns, and alignment of RA compliance penalties and CAISO backstop procurement. The Commission stated that an implementable RA framework would be one that addresses the above implementation details, as well as the five key principles.

On February 28, 2022, the Future of RA Reform Working Group Report (Reform Report) was submitted by the co-facilitators. The Reform Report outlined several proposals: three proposals on the structural framework, several

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<sup>110</sup> D.21-07-014 at 38. A detailed description of PG&E's slice-of-day proposal can be found in D.21-07-014 at 12-16.

<sup>111</sup> *Id.* at OP 1.

proposals on specific elements of a framework, as well as hedging and multi-year requirement proposals. Due to the length and detail of the proposals, we summarize the primary components below, as provided in the Reform Report.

#### **4.1. SCE's 24-Hour Slice Proposal**

SCE put forth a 24-hour slice proposal that requires each LSE to demonstrate that it has enough capacity to satisfy its specific gross load profile, including PRM, in all 24 hours on CAISO's "worst day" in that month.<sup>112</sup> The "worst day" would be defined as the "day of the month that contains the hour with the highest coincident peak load forecast." For an LSE that uses energy storage to meet requirements, the LSE must demonstrate it has excess capacity that offsets the storage usage plus efficiency losses. An LSE could combine the capabilities of its resource mix to cover all 24 hours.

The load forecast would be based on a bottoms-up approach where the LSE submits an hourly forecast. The existing coincident peak process would be retained, and LSEs' loads would be shaped based on historical 24-hour load shapes, adjusted by the CEC on a pro-rata basis to match the system demand forecast in each hour of the monthly worst day. SCE recommends that the PRM should be informed by the IRP proceeding's LOLE study (*e.g.*, 1-in-10 reliability standard) and apply to all months and hours. SCE proposes a process in the IRP proceeding to confirm the appropriate reliability standard.

An RA resource would offer all its capability to the CAISO market for the quantity of RA shown by the LSE. Resources without daily restrictions would retain the existing MOO for all 24 hours, while a resource with defined hours of

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<sup>112</sup> See Future of RA Working Group Report (Reform Report) at 8-25.

operation would have a MOO for the defined hours. SCE proposes that resources must be deliverable to qualify as RA and resources that are partially deliverable can only provide RA for the portion of the resource that is deliverable. SCE supports the continued use of CAISO's on-peak deliverability study process and use of the outputs for the 24-hour slice framework. The deliverability test could evolve over time to consider grid conditions in other hours.

Under SCE's proposal, resource attributes and capabilities would remain bundled. Resources may sell or trade portions of capacity to other LSEs to meet load shapes but cannot sell separate hourly products, as that would effectively sell the same RA capacity multiple times. For this reason, SCE expects that existing contracts would require little or no modification.

The proposal would eliminate the flexible RA requirement and the MCC buckets; however, the four-hour daily output availability requirement for use-limited resources and the local RA program would be retained.

The Commission would maintain a public RA Resource Master Database of resources eligible to sell RA, including the following attributes: Resource ID, available MW of RA capacity, hours available for production, other use limitations, continuous MWh run energy and charging efficiency (for storage), configuration (for hybrid and co-located), applicable hourly profile (for solar and wind). For confidential information, the Commission would have discretion to use a conservative value for the database and as the basis for RA counting.

All resources would continue to have a single monthly NQC representing the deliverability-adjusted peak-hour contribution. Most resources would use the NQC for all slices, but other resources would use hourly profiles consistent with expected capacity contribution in the slice, which would depend on

resource size, type, operational characteristics, deliverability status, and location.

SCE proposes the following for resource counting:

- Solar and wind resources: based on expected hourly capacity contribution (hourly profile) using a to-be-determined methodology, such as exceedance, hourly ELCC, or other.
- Standalone batteries: based on capacity and duration as shown by the LSE.
- Use-limited resources: based on capacity and available duration as shown by the LSE.
- Imports: based on available hours.
- Hybrid resources: requires additional discussion due to unique, complex issues.
- Other resources: based on single counting value for all hours (*e.g.*, NQC).

For compliance, SCE recommends verifying the following from an LSE:

- (1) Resources are being shown within their capability. Inconsistencies between an LSE's showing and the database must be corrected by the LSE to satisfy the showing.
- (2) Hourly requirements must be met or exceeded.
- (3) Excess capacity must be shown to cover shown battery capacity.

SCE favors using the current RA penalty structure when an LSE fails to satisfy a showing; that is, when an LSE fails to satisfy its requirements in any 24-hour slice. If the LSE fails in multiple hours, the penalty would be assessed based on the hour with the largest deficiency.

In addition, an LSE that fails a showing would be allocated CAISO backstop costs from deficiencies first, with remaining costs allocated to other impacted LSEs. SCE supports the continued use of CAISO's single-hour

deficiency test but to harmonize the new requirements, recommends that CAISO publicly identify the hour it will test for a deficiency and agree to use the Commission's hourly profile value for solar and wind for that hour, as well as the corresponding load level. The Commission can then provide CAISO the QC based on the ELCC of resources for that hour and CAISO can run its normal deliverability and NQC processes.<sup>113</sup> A deficient LSE should be allocated backstop costs regardless of whether it was deficient in the hour tested.

#### **4.2. PG&E's 24-Hour Slice Proposal Modifications**

PG&E supports much of SCE's 24-hour slice proposal but adds further detail and a different approach regarding resource counting, load forecasting, and MCC buckets.<sup>114</sup> PG&E states that these elements, with SCE's 24-hour proposal, would constitute a complete framework with few additional issues to resolve.

For solar and wind counting, PG&E recommends an exceedance-based methodology. PG&E asserts that exceedance is less administratively burdensome, more accurately reflects the hourly generation profile of resources, and facilitates easier bucketing of resources (by geography and/or technology) that enables greater levels of granularity. ELCC could be used in IRP and as a check in setting the appropriate exceedance level.

PG&E analyzed how solar and wind performed on high load days, defined as the peak day in the month. Using data from Open Access Same-time Information System (OASIS) and 12 x 24 profiles of solar and wind production on peak load days, PG&E found that for solar, a 60 percent exceedance level

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<sup>113</sup> SCE Reply Comments on Reform Report, April 1, 2022, at 7.

<sup>114</sup> See Reform Report at 26-31.

showed average hourly generation below peak day performance by a reasonable level. For wind, PG&E found that a 70 percent exceedance level resulted in balanced counting of wind generation capacity. PG&E proposes that initially, a single exceedance level be used across all hours and months but notes that time horizon and risk tolerance could be easily modified.

For dispatchable generation, PG&E recommends maximum generating capability (Pmax) with adjustments for ambient derates to account for performance issues, as an improvement over the status quo. For use-limited thermal units, PG&E recommends that hourly limits due to noise, pollution, or other permit-related limits be included in a broader set of data that Energy Division would make available on RA units. Resources with monthly limitations like starts or run hours would not be captured in this framework but could be explored later.

For storage, PG&E supports use of Pmax plus a gross up for charging loss rates specific to the resource. This offers flexibility in showing MWs across hours (*e.g.*, a 400 MWh battery could be shown for 50 MWs over 8 hours as opposed 100 MWs over 4 hours). PG&E does not oppose multiple cycles per day being shown if the contract allows. Additional showing constraints would need to be included to account for charging between cycles for multi-cycle showings.

For hybrids, PG&E supports using the existing methodology and updating it to account for losses. The existing method tests whether sufficient energy exists to charge the storage component and applies ELCC to any excess energy. This would be updated to apply exceedance to the excess energy. Additional considerations are whether the energy sufficiency test could use exceedance values of the resource and treatment of counting if the resource fails the sufficiency test (*i.e.*, for charging restrictions on storage, this element may not



count; if no charging restrictions, additional capacity would be needed in other hours to charge).

For hydroelectric, PG&E supports using the existing exceedance methodology at a resource level, as it gives more weight to poor hydro years and can be adapted to an hourly framework by changing the exceedance calculation process to yield hourly values instead of one gross peak value. For imports, PG&E recommends resource-specific imports be counted based on technology type. Non-resource-specific imports could be counted at the contract value, subject to the RA requirement that resources must be at least four hours in duration.

For demand response, PG&E defers to the CEC working group but notes that the methodology needs to provide hourly data of DR program availability for use in a slice-of-day framework. For non-dispatchable resources, PG&E notes that this is a small and generally static resource type. The current QC methodology could be used with a single value being applied to all hours, subject to availability constraints.

Regarding load forecasting based on the IEPR forecast, PG&E identifies two options:

- (1) Worst day: identifies the maximum load across all hours in the month and uses the forecast values for that particular day.
- (2) Maximum hourly values: based on the maximum observed value for each hour in the month.

PG&E recommends using maximum hourly values, as PG&E's analysis shows that the monthly peak of each hour does not always fall on the day with the maximum load and this option would provide extra assurances that load will be met in all hours.

PG&E recommends largely eliminating the MCC buckets since the 24-hour framework ensures that LSEs are bringing a mix of resources that once aggregated would ensure reliability across peak condition hours. PG&E supports retaining the DR cap, however, so that the system does not overly rely on DR during multi-day reliability events, which could result from program call limitations or customer fatigue.

#### **4.3. Gridwell's Two-Slice Proposal**

Gridwell<sup>115</sup> submits a proposal for a two-slice structure, with a gross peak and net peak load requirement.<sup>116</sup> The proposal has six key elements.

- (1) The monthly showing requirement and single monthly NQC construct would be maintained.
- (2) A biennial 1-in-10-year LOLE study would be performed to determine a system monthly RA gross load requirement that evaluates a loss of load potential across all hours.
- (3) QC methodologies would be updated for all use-limited resources using the ELCC method and thermal resources would be derated using historical ambient derate due to temperature-forced outages.
- (4) An aggregate monthly net load peak assessment would be added to ensure continuous reliability.
- (5) The existing penalty structure would be maintained and each deficient LSE would be penalized for the higher of its gross load deficiency or net peak deficiency in the month.
- (6) MCC buckets 1 to 4 would be eliminated in the 2024 RA year and the DR bucket would be eliminated in the following year after DR counting rules are refined.

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<sup>115</sup> Gridwell is not a party to this proceeding and submitted its proposal through the Working Group process. Because Gridwell is a non-party, there are limitations to the Commission considering and vetting an informal proposal without input from the sponsoring entity. The Commission has endeavored to evaluate the informal proposal with these limitations.

<sup>116</sup> See Reform Report at 32-41.

Energy sufficiency for charging storage would be captured by LOLE and ELCC studies. Insufficient charging energy would increase the RA requirement and impact ELCC values of solar, storage, etc. in order to maintain a 1-in-10-year LOLE. Storage charging needs should be incorporated into the IRP process to ensure sufficient renewable charging.

For the net peak assessment, the Commission and CAISO would use historical output profiles to cap solar contribution to ensure the net peak assessment only counts resources that are reasonably expected to operate in the test hour. Wind could adjust upward or downward as it typically produces more during the net peak. Any system net peak shortage would be assigned to deficient LSEs.

Gridwell's proposal contemplates minor changes to CAISO rules to accommodate the net peak load assessment. The existing MOO and outage replacement rules, as well as import must-offer and must-flow rules, would be maintained.

The existing ELCC construct would be expanded to value all use-limited resources in two phases. In phase one, the ELCC study would be expanded to include more classes that cover variable energy resources (*e.g.*, solar and wind) and use-limited resources (*e.g.*, energy-limited storage). In phase two, ELCC would be expanded for dispatchable hydro, non-dispatchable resources, DR, and non-resource-specific system resources. For wind, solar, storage, and hybrid resources, incremental ELCC values would be developed by classes that reflect specific technology, location, and duration. Hybrid and co-located resource ELCC values would be adjusted for any Investment Tax Credit (ITC) and/or intertie limitations.

For dispatchable thermal, UCAP-light would apply (*i.e.*, deliverable Pmax with ambient derate due to temperature adjustments). For use-limited dispatchable thermal, UCAP-light would apply until an ELCC or UCAP methodology is determined. For dispatchable hydro, non-dispatchable resources, and DR, existing rules would apply until an ELCC or UCAP methodology is determined. Resource-specific system imports would be subject to NQC based on the underlying resource supporting the import. For non-resource-specific system imports, existing rules would apply until an ELCC or UCAP methodology is determined.

#### **4.4. Comments on Structural Proposals**

All proposals and comments submitted by parties were considered; however, given the large number of parties and volume of comments in this track, some comments may receive little or no discussion.

##### **4.4.1. Comments on the 24-Hour Slice Proposals**

Numerous parties support SCE's 24-hour slice proposal, including ACP-CA, Cal Advocates, CalCCA, CEDMC, CEERT, CESA, CLECA, GPI, NRDC, PG&E, SCE, and SEIA/LSA.<sup>117</sup> Many parties assert that the 24-hour slice proposal best meets the Commission's objectives and direction in D.21-07-014.<sup>118</sup>

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<sup>117</sup> ACP-CA Comments on Reform Report, March 24, 2022, at 5; Cal Advocates Comments on Reform Report, March 24, 2022, at 1; CalCCA Comments on Reform Report, March 24, 2022, at 2; CEDMC Comments on Reform Report, March 24, 2022, at 2; CEERT Comments on Reform Report, March 24, 2022, at 2; CESA Comments on Reform Report, March 24, 2022, at 2; CLECA Comments on Reform Report, March 24, 2022, at 2; GPI Comments on Reform Report, March 24, 2022, at 1; NRDC Comments on Reform Report, March 24, 2022, at 2; PG&E Comments on Reform Report, March 24, 2022, at 1; SCE Comments on Reform Report, March 24, 2022, at 2; SEIA/LSA Comments on Reform Report, March 24, 2022, at 1.

<sup>118</sup> *See, e.g.*, CalCCA Comments on Reform Report, March 24, 2022, at 2; CEDMC Comments on Reform Report, March 24, 2022, at 2; CESA Comments on Reform Report, March 24, 2022, at 3; CLECA Comments on Reform Report, March 24, 2022, at 2; SCE Comments on Reform Report, March 24, 2022, at 2; SEIA/LSA Comments on Reform Report, March 24, 2022, at 2.

Parties assert that use of granular hourly slices would more accurately estimate capacity to meet reliability targets than longer-duration slices, thereby minimizing ratepayer costs.<sup>119</sup> Parties contend that the proposal directly addresses energy storage charging sufficiency concerns through RA filings on an individual LSE basis.<sup>120</sup>

Proponents of the 24-hour slice state that it is a more durable solution because it addresses gross and net load peaks, contemplates counting rules that accurately measure the reliability contribution of renewable and use-limited technologies, and can be adapted to address future reliability concerns while minimizing counting revisions.<sup>121</sup> Parties claim that the proposal would advance the state's environmental goals by requiring LSEs to show that their portfolios meet load in every hour.<sup>122</sup>

Numerous parties believe it is feasible to resolve the outstanding issues in SCE's proposal and implement the framework by 2024.<sup>123</sup> Alternatively, multiple

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<sup>119</sup> See, e.g., Cal Advocates Comments on Reform Report, March 24, 2022, at 5; CESA Comments on Reform Report, March 24, 2022, at 3; CLECA Comments on Reform Report, March 24, 2022, at 3; SEIA/LSA Comments on Reform Report, March 24, 2022, at 4.

<sup>120</sup> See, e.g., CAISO Comments on Reform Report, March 24, 2022, at 5; Cal Advocates Comments on Reform Report, March 24, 2022, at 5; CESA Comments on Reform Report, March 24, 2022, at 4; CLECA Comments on Reform Report, March 24, 2022, at 3.

<sup>121</sup> See, e.g., Cal Advocates Comments on Reform Report, March 24, 2022, at 5; CalCCA Comments on Reform Report, March 24, 2022, at 3; CEERT Reply Comments on Reform Report, April 1, 2022, at 3; CESA Comments on Reform Report, March 24, 2022, at 6; NRDC Comments on Reform Report, March 24, 2022, at 2; SCE Reply Comments on Reform Report, April 1, 2022, at 3; SEIA/LSA Comments on Reform Report, March 24, 2022, at 5.

<sup>122</sup> See, e.g., CESA Comments on Reform Report, March 24, 2022, at 4; NRDC Reply Comments on Reform Report, April 1, 2022, at 6; SCE Reply Comments on Reform Report, April 1, 2022, at 1.

<sup>123</sup> See, e.g., Cal Advocates Comments on Reform Report, March 24, 2022, at 3; CEERT Comments on Reform Report, March 24, 2022, at 2; CESA Comments on Reform Report, March 24, 2022, at 5; CLECA Comments on Reform Report, March 24, 2022, at 11; NRDC

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parties support a test year for SCE's proposal for 2024 with full implementation in 2025,<sup>124</sup> while others support a test year for 2023.<sup>125</sup> CAISO notes that any deviation from assessing peak demand using a single NQC value will require significant changes to CAISO's processes and will make it challenging for 2024 implementation.<sup>126</sup>

Opponents of the 24-hour slice proposal generally argue that it is too complex and not implementable by 2024,<sup>127</sup> that it may be more costly and challenging for LSEs to shape procurement to hourly requirements that may lead to over-procurement,<sup>128</sup> and that it may complicate LSE compliance.<sup>129</sup> Critics state that the 24-hour slice proposal does not rely on rigorous ELCC analysis and departs from a probabilistic framework.<sup>130</sup> Parties point out that the proposal

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Comments on Reform Report, March 24, 2022, at 6; PG&E Comments on Reform Report, March 24, 2022, at 1; SCE Comments on Reform Report, March 24, 2022, at 3; SEIA/LSA Comments on Reform Report, March 24, 2022, at 6.

<sup>124</sup> See, e.g., ACP-CA Comments on Reform Report, March 24, 2022, at 2; CAISO Comments on Reform Report, March 24, 2022, at 6; Cal Advocates Comments on Reform Report, March 24, 2022, at 3; CalCCA Reply Comments on Reform Report, April 1, 2022, at 3; CESA Reply Comments on Reform Report, April 1, 2022, at 4; Joint CCAs Comments on Reform Report, March 24, 2022, at 8; SCE Comments on Reform Report, March 24, 2022, at 3.

<sup>125</sup> See, e.g., NRDC Comments on Reform Report, March 24, 2022, at 6.

<sup>126</sup> CAISO Comments on Reform Report, March 24, 2022, at 6.

<sup>127</sup> See, e.g., Calpine Comments on Reform Report, March 24, 2022, at 1; MRP Comments on Reform Report, March 24, 2022, at 7; WPTF Comments on Reform Report, March 24, 2022, at 9.

<sup>128</sup> See, e.g., Calpine Comments on Reform Report, March 24, 2022, at 2; Joint CCAs Comments on Reform Report, March 24, 2022, at 4.

<sup>129</sup> See, e.g., Calpine Comments on Reform Report, March 24, 2022, at 4; CEJA/UCS Comments on Reform Report, March 24, 2022, at 10; MRP Comments on Reform Report, March 24, 2022, at 13; SDG&E Comments on Reform Report, March 24, 2022, at 8.

<sup>130</sup> See, e.g., Calpine Comments on Reform Report, March 24, 2022, at 4; CEJA/UCS Comments on Reform Report, March 24, 2022, at 6; MRP Reply Comments on Reform Report, April 1, 2022, at 9.

does not address multi-day reliability issues or account for trading resources and load obligations.<sup>131</sup>

Some parties, such as Joint CCAs, SDG&E, and CEJA/UCS, claim that the proposal could result in over-procurement of gas resources because they are available for all 24 hours, which may lead to unnecessary retention of gas power plants.<sup>132</sup> CEJA/UCS highlight, however, that there is insufficient analysis on this issue. Joint CCAs contend that this may create market power for gas resource owners, as gas contracts tend to be under long-term contracts or owned by IOUs. CLECA and NRDC disagree that the 24-hour proposal would hinder transition from gas-fired generation and state that with the elimination of the MCC buckets, LSEs can meet their 24-hour load with clean, use-limited resources, which will further the retirement of thermal resources.<sup>133</sup> CLECA states that California law has established a timeline for transition to clean energy, which must be met by all LSEs regardless of the proposal adopted.

#### **4.4.2. Comments on the Two-Slice Proposal**

Multiple parties support Gridwell's proposal, including AReM, Calpine, CalWEA, IEP, Joint CCAs, MRP, SDG&E, Shell Energy, and WPTF.<sup>134</sup> Parties

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<sup>131</sup> See, e.g., Calpine Comments on Reform Report, March 24, 2022, at 3; IEP Comments on Reform Report, March 24, 2022, at 4; Joint CCAs Comments on Reform Report, March 24, 2022, at 2; MRP Comments on Reform Report, March 24, 2022, at 12; SDG&E Comments on Reform Report, March 24, 2022, at 6.

<sup>132</sup> CEJA/UCS Comments on Reform Report, March 24, 2022, at 9; Joint CCAs Comments on Reform Report, March 24, 2022, at 4; SDG&E Comments on Reform Report, March 24, 2022, at 6.

<sup>133</sup> CLECA Reply Comments on Reform Report, April 1, 2022, at 5; NRDC Reply Comments on Reform Report, April 1, 2022, at 5.

<sup>134</sup> Calpine Comments on Reform Report, March 24, 2022, at 1; CalWEA Comments on Reform Report, March 24, 2022, at 1; IEP Comments on Reform Report, March 24, 2022, at 1; Joint CCAs Comments on Reform Report, March 24, 2022, at 1; MRP Comments on Reform

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generally state that the proposal provides an acceptable level of granularity and reliability by applying and updating ELCC values, which is a more rigorous, probabilistic approach to assigning capacity value.<sup>135</sup> The proposal is effectively the current RA framework, or an enhanced version, with a new PRM and ELCC values applied to more resources based on an LOLE study.<sup>136</sup> By maintaining much of the current RA program, the proposal has limited risk of unintended consequences, does not overly disrupt the existing bilateral RA framework, and requires only minor changes to CAISO's tariff rules.<sup>137</sup> Because the proposal only requires updating the PRM and ELCC values based on an LOLE study, the proposal is readily implementable by 2024.<sup>138</sup>

The two-slice proposal addresses energy storage charging sufficiency using ELCC because when ELCC values are determined, all hours are simulated and if storage is not able to sufficiently charge for reliability purposes, loss of load events in the modeling and ELCC values would reflect this.<sup>139</sup> The proposal

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Report, March 24, 2022, at 6; Shell Energy Comments on Reform Report, March 24, 2022, at 2; WPTF Comments on Reform Report, March 24, 2022, at 1.

<sup>135</sup> See, e.g., Calpine Comments on Reform Report, March 24, 2022, at 4; IEP Comments on Reform Report, March 24, 2022, at 8; SDG&E Comments on Reform Report, March 24, 2022, at 4; Shell Energy Comments on Reform Report, March 24, 2022, at 5.

<sup>136</sup> See, e.g., Calpine Comments on Reform Report, March 24, 2022, at 5; Joint CCAs Comments on Reform Report, March 24, 2022, at 3, MRP Comments on Reform Report, March 24, 2022, at 7; SDG&E Comments on Reform Report, March 24, 2022, at 4.

<sup>137</sup> See, e.g., CalWEA Comments on Reform Report, March 24, 2022, at 2; IEP Comments on Reform Report, March 24, 2022, at 3, 6; MRP Comments on Reform Report, March 24, 2022, at 7; WPTF Comments on Reform Report, March 24, 2022, at 9.

<sup>138</sup> See, e.g., MRP Comments on Reform Report, March 24, 2022, at 7; Calpine Comments on Reform Report, March 24, 2022, at 5; CalWEA Comments on Reform Report, March 24, 2022, at 2; WPTF Comments on Reform Report, March 24, 2022, at 7.

<sup>139</sup> See, e.g., Calpine Comments on Reform Report, March 24, 2022, at 4; IEP Comments on Reform Report, March 24, 2022, at 3; SDG&E Comments on Reform Report, March 24, 2022, at 5.



better addresses multi-day reliability events if such events are reflected in the inputs for the ELCC analysis.<sup>140</sup>

Some parties state that the two-slice framework fails to meet the Commission's principles as directed in D.21-07-014.<sup>141</sup> Critics assert that it maintains the existing RA framework with one requirement for a net load reliability check.<sup>142</sup> Parties also argue that there is no requirement to evaluate hours beyond the gross peak and thus, there is no granularity in meeting hourly needs.<sup>143</sup> PG&E and NRDC point out that CAISO has stated that the gross peak and net peak demand hours will converge by 2023, which means the two-slice proposal appears to be the existing RA framework without the MCC requirements.<sup>144</sup> Parties argue that by removing the MCC buckets, the proposal has a negative impact on reliability because there is no mechanism to ensure LSEs bring capacity across hours other than the gross peak.<sup>145</sup>

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<sup>140</sup> See, e.g., Calpine Reply Comments on Reform Report, April 1, 2022, at 2; Joint CCAs Comments on Reform Report, March 24, 2022, at 2.

<sup>141</sup> See, e.g., CEERT Reply Comments on Reform Report, April 1, 2022, at 3; NRDC Comments on Reform Report, March 24, 2022, at 3; PG&E Comments on Reform Report, March 24, 2022, at 5; SCE Reply Comments on Reform Report, April 1, 2022, at 2.

<sup>142</sup> See, e.g., NRDC Comments on Reform Report, March 24, 2022, at 3; PG&E Comments on Reform Report, March 24, 2022, at 5; SCE Comments on Reform Report, March 24, 2022, at 2.

<sup>143</sup> See, e.g., CLECA Reply Comments on Reform Report, April 1, 2022, at 4; PG&E Comments on Reform Report, March 24, 2022, at 5; SCE Comments on Reform Report, March 24, 2022, at 2; SEIA/LSA Reply Comments on Reform Report, April 1, 2022, at 6.

<sup>144</sup> PG&E Reply Comments on Reform Report, April 1, 2022, at 2; NRDC Comments on Reform Report, March 24, 2022, at 3.

<sup>145</sup> See, e.g., CLECA Reply Comments on Reform Report, April 1, 2022, at 4; PG&E Comments on Reform Report, March 24, 2022, at 6; SCE Comments on Reform Report, March 24, 2022, at 2.

Numerous parties state that there is no explicit requirement to ensure sufficient energy is available to meet load and charge storage in all hours.<sup>146</sup> CAISO emphasizes that although QC values may be derated under an ELCC approach, the shown RA fleet may significantly differ from the portfolio used to derive ELCC values, and validating the RA fleet based on capacity values may not ensure adequate energy to meet demand and charging needs.<sup>147</sup>

Opponents argue that the proposal relies on a new LOLE and ELCC study within the next year and regular updates thereafter, which is administratively burdensome and complex.<sup>148</sup> Parties contend that applying single ELCC values to assess energy sufficiency to most technology types is increasingly complicated, particularly as ELCC will be required to develop more granularity and flexibility to capture location and technology types.<sup>149</sup> CESA states that ELCC values are highly variable and fundamentally determined by assumptions in the calculations, which leads to volatility of values that creates a complex landscape for project financing.<sup>150</sup> CESA and CLECA contend that relying on single ELCC values for wind and solar is not appropriate, as they undervalue contributions

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<sup>146</sup> See, e.g., CAISO Comments on Reform Report, March 24, 2022, at 4; CLECA Comments on Reform Report, March 24, 2022, at 3; CESA Comments on Reform Report, March 24, 2022, at 4; GPI Reply Comments on Reform Report, April 1, 2022, at 3; PG&E Comments on Reform Report, March 24, 2022, at 5; SCE Reply Comments on Reform Report, April 1, 2022, at 2.

<sup>147</sup> CAISO Comments on Reform Report, March 24, 2022, at 4.

<sup>148</sup> See, e.g., CESA Comments on Reform Report, March 24, 2022, at 5; SCE Reply Comments on Reform Report, April 1, 2022, at 3; SEIA/LSA Reply Comments on Reform Report, April 1, 2022, at 4.

<sup>149</sup> See, e.g., CESA Comments on Reform Report, March 24, 2022, at 5; PG&E Comments on Reform Report, March 24, 2022, at 5; SCE Reply Comments on Reform Report, April 1, 2022, at 3; SEIA/LSA Reply Comments on Reform Report, April 1, 2022, at 2.

<sup>150</sup> CESA Comments on Reform Report, March 24, 2022, at 3.

during the gross peak and overvalue contributions at the net peak, leading to the challenges that drove emergency reliability procurement.<sup>151</sup>

#### **4.5. Discussion of Structural Proposals**

The Commission appreciates the substantial effort and thorough discussion undertaken by parties over nearly six months to refine the proposals in the Reform Report, and particularly recognizes the efforts put forth by the workshop co-facilitators.

To assess the structural reform proposals submitted in the Reform Report, we consider the principles and concerns identified in D.21-07-014. These principles guided the Commission in determining that a slice-of day framework would more effectively address the increased penetration of renewable resources and dependence on use-limited resources by basing reliability needs on a more granular level.

In addition, while the Commission seeks to coordinate structural changes to the RA framework with the planning efforts undertaken in IRP, it is important to bear in mind that short-term reliability needs require more granularity than IRP planning efforts. These needs stem from the fact that short-term planning is focused on ensuring that CAISO has sufficient RA resources committed (new and existing), through a MOO to bid, into CAISO's day-ahead and real-time energy markets during all hours of the year.

Short-term planning also considers near-term local and flexible reliability needs to ensure that resources (new and existing) are committed to provide CAISO the resource attributes necessary to run the grid reliably in all hours over each short-term compliance period. If CAISO has insufficient resources to meet

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<sup>151</sup> CESA Comments on Reform Report, March 24, 2022, at 4; CLECA Comments on Reform Report, March 24, 2022, at 7.

its reliability needs (system, flex and local), it may utilize backstop procurement, either through the Capacity Procurement Mechanism (CPM) or Reliability Must Run (RMR) process. The RA program seeks to minimize the likelihood of such backstop procurement. By contrast, IRP planning efforts view reliability from the perspective of whether more new resources are needed to ensure the system can achieve a 0.1 LOLE reliability criteria in the mid- to long-term planning horizons.

In considering the structural proposals and parties' extensive comments, the Commission finds that Gridwell's two-slice proposal fails to satisfy the principles and direction set by the Commission in D.21-07-014. The Commission concurs with comments that the two-slice proposal is not in fact a slice-of-day framework, but rather, a two-period proposal that would move to one period by 2023 when the net peak and gross peak hours are forecasted to converge. A one-point framework is the same as the existing RA framework today. The current RA framework also utilizes ELCC for solar and wind resources, and includes the MCC bucket structure to limit reliance on use-limited resources in meeting the one-point requirement. While the two-slice proposal seeks to enhance current resource counting rules by expanding ELCC to all use-limited resources, it proposes to eliminate use of the MCC buckets. The two-slice proposal also fails to include an explicit requirement for ensuring sufficient energy is available for charging storage.

The Commission finds that removal of the MCC bucket structure on what is expected to become a one-period reliability system, without an energy sufficiency check, would result in a less reliable framework than the current RA program. While the current RA framework does not account for energy sufficiency, it provides assurances that LSEs will not meet their entire monthly

requirements with energy storage or demand response resources, assurances not found in the two-slice framework.

In addition, the two-slice proposal relies on performing regular ELCC studies for various resource classifications and zones. We agree with multiple parties that point out the significant effort and challenges involved in performing ELCC studies for RA purposes on a regular basis and the uncertainty in RA values that may arise as the portfolio of resources evolves from one study to the next. The two-slice framework also recommends continued reliance on single-value estimates for variable energy resources, which undervalue contributions during the current peak and overvalue contributions during the net peak. In summary, the two-slice framework fails to address the Commission's concerns regarding the current RA program.

The Commission finds that SCE's 24-hour slice proposal best satisfies the principles and objectives identified in D.21-07-014. With the growing penetration of variable energy and use-limited resources, we observe that the 24-hour slice framework can better address reliability than the current MCC bucket structure. We have previously emphasized the concern that the MCC buckets are not binding and do not account for energy storage charging needs. The 24-hour framework directly addresses energy sufficiency at an individual LSE level by requiring each LSE to provide sufficient excess energy to charge any storage it shows across the 24-hour slices.

The 24-hour framework also restricts the extent to which use-limited resources can count across the 24-hour compliance period by linking a resource's value to its physical limitations, confirmed by a public RA Resource Master Database. The RA Resource Master Database would also be confirmed against operational capabilities from CAISO's Master File. Inclusion of a resource on the

database would render the values binding, and allow for RA compliance to be based on the database.

The use of periodically updated LOLE studies to set the PRM used for RA compliance, as proposed by SCE, is likely to ensure that the contracted RA fleet meets the established reliability criteria. The 24-hour framework additionally provides more certainty in RA values, as compared to the two-slice proposal, because RA value streams would be based on an expected hourly capacity value (subject to a resource's operational limitations), which would be independent of the assumed aggregate system portfolio of resources, as with ELCC studies. Such certainty in RA value streams is critical to future transactability of resources. Moreover, a key aspect of the 24-hour proposal is that capacity values remain bundled across the 24-hour compliance period. The bundled aspect ensures that LSEs and suppliers continue to transact for a monthly product that meets the 24-hour requirement, as is done today.

We are also persuaded that allowing more slices across the compliance period will allow for better representation of VERs' contributions to reliability and will minimize costs to ratepayers, as compared to a one- or two-slice structure. With respect to advancing California's environmental goals, better representation of these resources will allow for full participation and integration of use-limited renewable resources necessary to achieve the state's clean energy goals. The 24-hour proposal also represents a durable framework that can evolve as the state's energy and environmental policy goals, which include widespread electrification, transform the generation supply portfolio and demand requirements.

The Commission recognizes that the 24-hour framework departs from probabilistic planning, as is used in the IRP process. We find, however, that a

more deterministic approach is necessary to achieve short-term reliability needs as it assesses the needs of the grid for every hour of the day. For example, the current solar ELCC values represent aggregate contributions within the month (in the form of one value); this value, however, does not capture hourly granularity, where solar can fairly reliably meet load in the middle of the day but provide little or no contribution later in the evening. Likewise, a storage ELCC, if one were to be adopted, would also have one value but would not reflect the significant charge and discharge limitations of the storage resource over the course of the day.

Regarding the implementation timeline, the 24-hour framework raises complexities and outstanding issues that must be further developed; however, we do not view the outstanding issues that remain to be developed as a barrier to implementing the 24-hour framework. We also agree with the numerous parties that recommend a 2024 test year prior to full implementation. Given the complexities of implementing a new statewide RA framework, we find it prudent to consider a test year in 2024 to allow additional time for implementation and potential adjustments. This would result in full implementation of the new RA framework to the 2025 RA year. We further discuss the components of a test year below.

For these reasons, the Commission concludes that SCE's 24-hour slice proposal best addresses the principles and concerns raised in D.21-07-014 and should be further developed in workshops, as detailed below. Accordingly, SCE's 24-hour slice framework is adopted, with modifications, and as outlined in Appendix A.

#### **4.6. Discussion on Elements of the 24-Hour Framework**

We next consider the specific elements of SCE's 24-hour slice framework. Note that the discussion references specific element proposals from the Reform Report, as well as elements of PG&E's and SCE's structural proposals.

##### **4.6.1. Load Forecast Methodology**

SCE's 24-hour proposal recommends use of a "worst day" forecast to determine individual LSEs' monthly RA requirements.<sup>152</sup> PG&E supports using either the worst day in each month, or "maximum hourly values" based on the maximum observed value for each hour in the month.<sup>153</sup>

The CEC proposes a bottoms-up approach to apply to the worst day forecast under the 24-hour framework, similar to the current RA load forecast process.<sup>154</sup> Because the current IEPR forecast includes an 8760 hours/year forecast approach, the CEC recommends extracting the monthly peak day or worst day load profiles. For coincidence adjustment, a similar analysis to the existing process would be done to adjust multiple slices or hours. LSEs would submit a non-coincident forecast that includes their peak demand and, at minimum, a 24-hour forecast of the LSE's own peak day. The CEC recommends a dry-run forecast in 2022, in which LSEs submit hourly forecasts for 2023 to allow the CEC to test new methods and identify challenges.

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<sup>152</sup> Reform Report at 10.

<sup>153</sup> *Id.* at 31.

<sup>154</sup> *See id.* at 48-49.



Parties that support the CEC's proposal include CLECA, Cal Advocates, GPI, and SCE.<sup>155</sup> CLECA opposes use of "maximum hourly values" (or worst hour) and argues that creating synthetic load shapes breaks the relationship between weather of the worst day and the load forecast.<sup>156</sup> CLECA posits that the worst hour may create difficulties for the CEC to calibrate the total of LSEs' load forecasts to match the CEC's system peak forecast.

The Commission notes that in practice, the maximum hourly approach may differ minimally from the worst day approach, resulting in significantly higher mid-day hourly values only for a few months of the year. By contrast, the worst day approach is a more straightforward means of developing individual LSE monthly load shapes that is further supported by the CEC's implementation proposal. As such, we conclude that the worst day approach is the appropriate method for the 24-hour framework and that the CEC's proposal is a reasonable approach to establishing individual LSE hourly load forecasts. Accordingly, the CEC's load forecast approach shall be utilized for the 24-hour framework.

We also agree with the CEC that a dry run load forecast in 2022 for 2023 is necessary and request that Energy Division conduct a dry run load forecast filing, in coordination with the CEC, to identify challenges and determine if refinements to the methodology are needed. Any proposed refinements to the load forecast process that may result from the test filing should be incorporated into the workstreams identified in Section 4.7.

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<sup>155</sup> Cal Advocates Comments on Reform Report, March 24, 2022, at 17; CLECA Comments on Reform Report, March 24, 2022, at 4; GPI Comments on Reform Report, March 24, 2022, at 5; SCE Reply Comments on Reform Report, April 1, 2022, at 4.

<sup>156</sup> CLECA Comments on Reform Report, March 24, 2022, at 4.

#### 4.6.2. Solar and Wind Load Profiles

PG&E, SEIA/LSA/Vote Solar (VS), and CalWEA put forth proposals targeted at development of hourly profiles for wind and solar resources. As further detailed above, PG&E recommends an exceedance methodology for wind and solar that is benchmarked to average production during stressed system conditions (average historical production data from monthly peak days).<sup>157</sup> PG&E proposes use of the exceedance methodology and recommends a 60 percent exceedance level for solar and a 70 percent exceedance level for wind based on analysis that compared these exceedance levels to average production on peak days.

SEIA/LSA/VS recommend an exceedance value for solar during net load peak hours that closely tracks average ELCC.<sup>158</sup> These parties assert that their analysis shows that the P50 (*i.e.*, 50 percent probability of exceedance) output of solar on the CAISO system during net load peak hours reasonably tracks the current RA capacity value of the CAISO solar portfolio using the average ELCC of solar. SEIA/LSA/VS assert that use of P50 would avoid the portfolio issues raised if the exceedance value is significantly higher than 50 percent.

CalWEA proposes a methodology for wind and solar that seeks to capture the correlation between wind and solar output and actual system load, referred to as Effective Net Load Reduction (ENLR).<sup>159</sup> ENLR calculates a simple average of historical hourly VER output during those hours of the year when load is higher than a defined threshold. CalWEA recommends a 70 percent threshold that would look at hours of production when load was 70 percent of maximum

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<sup>157</sup> Reform Report at 27.

<sup>158</sup> *See id.* at 41-44.

<sup>159</sup> *See id.* at 45-47.

load or higher for each hour. The calculation would rely on historical production data from the previous three to five historical years.

In comments, NRDC recommends using a synthetic production shape representing the “worst day” with varying percentiles of the worst day definition.<sup>160</sup> NRDC recommends exploring a profile development method that analyzes solar, wind, and load profiles on days when loss of load events occur within the LOLE model as an informative benchmark.

Several parties support an exceedance methodology for VER QC counting, such as SCE and Cal Advocates, with IEP supporting PG&E’s proposal.<sup>161</sup> SCE also supports NRDC’s worst day methodology. SEIA/LSA states that they may consider adjusting their exceedance proposal in light of Energy Division’s new average ELCC analysis.<sup>162</sup>

The Commission notes that for both an exceedance methodology or a worst day methodology, there are challenges to determining where to set the exceedance level and how to define the worst day. Relying on actual production data, rather than synthetically-produced data, or methodologies tied to the results of modeling outputs, will result in a more implementable framework that can be refreshed annually. The Commission finds that PG&E’s exceedance methodology provides a sufficient means to determine solar and wind profiles that are benchmarked to stressed system conditions. We acknowledge, however, that the exceedance levels recommended by PG&E are based on a limited set of data (average monthly peak day production for each historical year) and require

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<sup>160</sup> NRDC Comments on Reform Report, March 24, 2022, at 10.

<sup>161</sup> IEP Comments on Reform Report, March 24, 2022, at 11; SCE Reply Comments on Reform Report, April 1, 2022, at 6; Cal Advocates Comments on Reform Report, March 24, 2022, at 5.

<sup>162</sup> SEIA/LSA Comments on Reform Report, March 24, 2022, at 10.

further development to ensure that the appropriate exceedance levels are benchmarked against a more robust dataset. With this guidance, we direct parties to continue development of PG&E's exceedance methodology as part of the workstreams identified in Section 4.7.

#### **4.6.3. Dispatchable Resource Counting<sup>163</sup>**

Some parties support applying a "UCAP-light" mechanism to dispatchable resources, such as CLECA, SCE, Shell Energy, and PG&E.<sup>164</sup> A UCAP-light mechanism would adjust the Pmax value of these resources to account for ambient derates due to temperature. The Commission concurs that ambient derates are a physical limitation that should be reflected in the RA value for dispatchable resources and would be an enhancement over the status quo. We are aware that some generators are currently lowering QC values to account for ambient derates through a requested reduction in CAISO's annual NQC process.

While parties may have discussed a UCAP-light (ambient derate) mechanism in workshops at a conceptual level, no detailed methodology has been proposed. Developing such a mechanism would require further input from CAISO and stakeholders. If a UCAP-light mechanism were to utilize CAISO outage data associated with ambient derates due to temperature, the mechanism may also run into implementation barriers, as identified by CAISO with respect to the overall UCAP design. Despite potential implementation challenges, the Commission sees merit in developing a UCAP-light mechanism for initial implementation of the 24-hour framework.

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<sup>163</sup> This section applies to all dispatchable resources not explicitly discussed elsewhere.

<sup>164</sup> Reform Report at 29; CLECA Comments on Reform Report, March 24, 2022, at 6; SCE Reply Comments on Reform Report, April 1, 2022, at 8; Shell Energy Comments on Reform Report, March 24, 2022, at 5.

The Commission encourages parties to attempt to establish a UCAP-light mechanism to apply to dispatchable resources as part of the workstreams identified in Section 4.7. If implementation barriers cannot be overcome, dispatchable resources shall continue to count at their Pmax value, as they do today, until a mechanism is developed.

For use-limited dispatchable resources, PG&E recommends that hourly limits due to noise, pollution or other permit-related limits be included in a broader set of data that Energy Division would make available on RA units.<sup>165</sup> The Commission agrees with PG&E and directs parties and Energy Division to capture use limitations in the RA Resource Master Database through the identified workstreams, to the extent possible.

#### **4.6.4. Energy Storage and Long-Duration Energy Storage Resource Counting**

SCE proposes that energy storage resources count based on Pmax or UCAP-light restricted to their daily resource capabilities (*e.g.*, maximum daily run hours, maximum continuous energy, and storage efficiency) and that excess capacity be shown to cover battery capacity with efficiency losses.<sup>166</sup> SCE also proposes that energy storage resources be allowed to count for multiple cycles, provided the downtime needed for another full charge is accounted for in such cycles. SCE recommends developing energy storage profiles to refine these counting rules. Hydrostor opposes counting methods that would allow 4-hour storage to count for multiple cycles across a day and refers to this allowance as double counting.<sup>167</sup> PG&E is not opposed to allowing multiple cycles per day,

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<sup>165</sup> Reform Report at 29.

<sup>166</sup> Reform Report at 14.

<sup>167</sup> Hydrostor Comments on Reform Report, March 24, 2022, at 5.

provided the contract language allows for them.<sup>168</sup> PG&E notes that these showing constraints would need to be included to account for charging between cycles for multi-cycle showings.

The Commission sees value in allowing energy storage resources to count for multiple cycles per day, provided that the contract language allows for it. If the storage resource is capable and contracted to provide multiple cycles, it should be allowed to count in this manner, provided that the LSE shows sufficient capacity to charge the storage and account for losses between each cycle. We observe, however, that more discussion is needed on this issue to consider any unintended consequences.

The Commission determines that SCE's storage counting proposal based on Pmax or UCAP-light, restricted to daily resource capabilities, is reasonable. Accordingly, Pmax or UCAP-light (if developed) restricted to daily resource capability shall apply to energy storage resources under the 24-hour framework. Excess capacity must be show shown to cover battery capacity with efficiency losses. With respect to allowing storage resources to count for multiple cycles, we direct parties to discuss and develop this proposal in the identified workstreams in Section 4.7.

In addition, Cal Advocates, CEERT, Form Energy, GPI, Hydrostor, LDESAC, and PG&E state that multi-day reliability events, as well as the proper valuation of long-duration energy storage (LDES) to account for energy sufficiency, should be further developed and accounted for in the 24-hour

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<sup>168</sup> Reform Report at 29.

framework.<sup>169</sup> Form Energy voices concerns that the 24-hour framework requires sufficient capacity to fully charge storage in a single day and could exclude LDES, which can discharge over multiple days, from providing RA value. LDESAC urges that credit be given for benefits of LDES, such as multi-day and seasonal benefits. CESA states that concerns about multi-day and seasonal needs can be alleviated in part by CESA's proposed seasonal charge scheme, which allows LSEs to take excess spring-month overgeneration to provide charging sufficiency for storage assets in summer or winter months.<sup>170</sup>

The Commission agrees with parties that LDES valuation and multi-day reliability event issues should be included in workshop discussions. We recognize that ensuring LDES resources are properly valued across the slice-of-day framework is critical to the durability and success of the 24-hour framework. Parties are directed to discuss these issues in the workstreams identified in Section 4.7, in coordination with the development of the RA Resource Master Database and the elimination of the MCC buckets, as further discuss below.

We are aware that issues around the valuation of long-duration storage and multi-day reliability events may not be fully addressed prior to initial implementation of the 24-hour framework. Parties should nevertheless begin discussions of these topics in the identified workstreams and develop an implementable proposal to the extent possible.

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<sup>169</sup> Cal Advocates Comments on Reform Report, March 24, 2022, at 4; CEERT Reply Comments on Reform Report, April 2, 2022, at 6; Form Energy Comments on Reform Report, March 24, 2022, at 4; GPI Reply Comments on Reform Report, April 2, 2022, at 4; Hydrostor Comments on Reform Report, March 24, 2022, at 6; LDESAC Comments on Reform Report, March 24, 2022, at 2; PG&E Reply Comments on Reform Report, April 1, 2022, at 6.

<sup>170</sup> CESA Reply Comments on Reform Report, April 1, 2022, at 6.

#### 4.6.5. Hybrid and Co-Located Resource Counting

Under SCE's 24-hour slice proposal, hybrid and co-located resources would be valued based on the general principle that they be shown within their capabilities.<sup>171</sup> SCE does not offer a specific proposal but recommends further discussion on the valuation of these resources, particularly regarding profiles for partially deliverable resources. PG&E proposes maintaining the existing methodology for hybrid resource but using exceedance for excess renewable generation as opposed to the current application of ELCC and accounting for charging losses.<sup>172</sup> Cal Advocates agrees that resource counting for hybrid and co-located resources is appropriately represented by current QC rules and that additional details should be discussed in workshops.<sup>173</sup> SEIA/LSA recommend starting with the current counting rules for hybrids and further refining to recognize different hybrid configurations.<sup>174</sup> CESA advocates for more clarity regarding valuation of paired resources, particularly for paired assets that claim a portion of the ITC.<sup>175</sup>

The Commission agrees with parties that support applying the existing additive methodology as a starting point for the 24-hour framework. We also agree with PG&E that this methodology will need to be updated to use exceedance (rather than ELCC) in valuing the solar and wind portion of the resource and to account for charging losses. Lastly, we observe that further discussion is needed to address different hybrid configurations, ITC charging

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<sup>171</sup> See Reform Report at 14.

<sup>172</sup> *Id.* at 30.

<sup>173</sup> Cal Advocates Comments on Reform Report, March 24, 2022, at 6.

<sup>174</sup> SEIA/LSA Comments on Reform Report, March 24, 2022, at 10.

<sup>175</sup> CESA Comments on Reform Report, March 24, 2022, at 7.



assumptions, and partial deliverability counting under the 24-hour framework. The collection of resource data is a key element to effectively implementing the 24-hour framework. PG&E's proposal should be further refined to capture the necessary data to reflect hybrid and co-located configurations across the 24-hour slices through the development of the RA Resource Master Database. The Commission directs parties to further refine PG&E's proposal as part of the workstreams identified in Section 4.7. Development of all counting methodologies need to be coordinated with the development of the RA Resource Master Database.

#### **4.6.6. Other Resource Counting Methods**

For hydroelectric resources, SCE's 24-hour slice proposal supports retaining the existing hydro QC methodology and applying the monthly value to all hours.<sup>176</sup> PG&E also advocates for using the current methodology, with the modification that 24 hourly values are calculated for each month, rather than one gross peak value.<sup>177</sup>

PG&E's proposal will result in resource-specific monthly shapes that must be included in the RA Resource Master Database and such hourly shapes at a resource level may be too complex for initial implementation. SCE's proposal, by contrast, utilizes the current exceedance methodology to value hydro resources at a resource level but does not require shapes at a resource level. The Commission deems SCE's proposal to be an appropriate, less complicated approach for the 24-hour framework. Accordingly, the existing QC methodology for hydro resources shall be applied to hydro resources under the 24-hour

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<sup>176</sup> Reform Report at 15.

<sup>177</sup> *Id.* at 30.

framework, with monthly values applied to all hours. In future years, it may be appropriate to expand the counting rules to monthly load shapes at a resource level or a resource grouping level.

For non-dispatchable resources, PG&E recommends using the current QC methodology, with a single value applied to all hours, subject to availability constraints.<sup>178</sup> SCE also supports using the current QC methodology but recommends that the resource be permitted to count across all 24 slices, rather than be subject to availability restrictions.<sup>179</sup> The Commission finds that PG&E's proposal is a reasonable approach as it would capture daily use limitations that would better reflect resources' availability across the 24-hour framework. Accordingly, the existing QC methodology for non-dispatchable resources shall be applied to non-dispatchable resources under the 24-hour framework, with a single value applied to all hours, subject to availability constraints. Availability constraints should be identified through the development of the RA Resource Master Database.

For import resources, SCE recommends that imports be counted based on their contracted amount and duration, and that use-limited resources should be subject to a minimum 4-hour daily output availability requirement.<sup>180</sup> PG&E recommends that resource-specific imports should use the counting rules applicable to that particular resource type and that non-resource-specific imports should count at the contract value, subject to the requirement that resources be at least four hours in duration.<sup>181</sup>

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<sup>178</sup> *Id.*

<sup>179</sup> *Id.* at 15.

<sup>180</sup> *Id.* at 14.

<sup>181</sup> *Id.* at 30.

The Commission agrees with SCE and PG&E that all use-limited resources should continue to be subject to the minimum four-hour availability requirement to qualify as RA. We also see merit in PG&E's proposal as it would reflect current import rules and apply those rules (for both non-specified imports and specified imports) to the 24-hour framework. Together these proposals would ensure that imports provide a monthly capacity value reflective of their monthly use limitations. Accordingly, PG&E's and SCE's proposals for import resources shall be applied to import resources under the 24-hour framework. Import counting rules should be coordinated with discussion of the elimination of the MCC buckets, as further discussed below.

For DR resources, CLECA recommends the current LIP process to value DR resources under a 24-hour framework.<sup>182</sup> SCE comments that CLECA's proposal is consistent with SCE's principle that counting should reflect expected capacity contribution of each slice but defers consideration to the CEC Working Group process.<sup>183</sup> Consideration of a DR QC counting methodology should be deferred to the CEC Working Group, as directed in Section 3.4. We encourage CLECA to further develop its proposal as part of the CEC Working Group, as well as encourage other proposed methodologies compatible with the 24-hour framework.

#### **4.6.7. Planning Reserve Margin**

SCE proposes that the Commission initiate a stakeholder process in the IRP proceeding on reliability metrics to confirm the appropriate reliability standard (*e.g.*, 1-in-10) and to calculate the PRM necessary to achieve that

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<sup>182</sup> *See id.* at 69-72.

<sup>183</sup> SCE Reply Comments on Reform Report, April 1, 2022, at 8.

standard via an LOLE study.<sup>184</sup> The IRP discussion should inform the PRM used in the RA program. As a starting point, SCE proposes one PRM to apply to all hours of the year.

In comments, NRDC states that it has completed a “proof of concept” calibration of the slice-of-day framework based on Energy Division’s LOLE study and outlines steps necessary to finalize the parameterization and implementation of the 24-hour framework.<sup>185</sup> NRDC asserts that PRM development is a function of policy choices made to count underlying resources and that the current PRM is impacted, for example, by whether outages for fossil resources are included or excluded. SCE agrees with NRDC’s rationale and believes that finalizing the counting rules, particularly for wind and solar, is a necessary first step to calculating the appropriate PRM.<sup>186</sup> PG&E largely supports the steps outlined by SCE but suggests that the process leverage ongoing work as part of the LOLE study and engage stakeholders to consider other ideas, such as the process outlined by NRDC.<sup>187</sup>

SEIA/LSA support continuing efforts to periodically update LOLE studies to verify that the key parameters of the reform framework, such as counting rules and the PRM, result in a portfolio that meets system reliability goals.<sup>188</sup> CAISO urges the Commission not to delay analysis and vetting of Energy

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<sup>184</sup> Reform Report at 10.

<sup>185</sup> NRDC Opening Comments on Reform Report, March 24, 2022, at 7.

<sup>186</sup> Reply Comments on Reform Report, April 1, 2022, at 7.

<sup>187</sup> PG&E Reply Comments on Reform Report, April 1, 2022, at 5.

<sup>188</sup> SEIA/LSA Reply Comments on Reform Report, April 1, 2022, at 3.

Division's LOLE model assumptions while aspects of the reform framework are developed.<sup>189</sup>

As discussed in Section 3.3.2, a minimum 17 percent PRM is adopted for 2024, and further analysis on increasing above 17 percent for 2024 will be informed by analysis undertaken in the IRP proceeding. The Commission recognizes that calibration of the 17 percent PRM to the 24-hour framework cannot feasibly be done, as the 17 percent does not match the current LOLE modeling output. As such, converting the results of the LOLE study to the counting rules applicable to the 24-hour framework should await the refreshed LOLE outputs from the IRP proceeding. Once refreshed LOLE outputs are available, conversion of the outputs to the 24-hour framework counting rules need to be completed, and NRDC's "proof of concept" template should be leveraged for the conversion.

#### **4.6.8. Compliance Penalties**

SCE's proposal would utilize the current RA penalty framework to penalize LSEs that fail to meet monthly RA requirements across the 24-hour framework.<sup>190</sup> LSEs would be penalized based on the hour with the largest deficiency. Calpine endorses this approach and reasons that an LSE's alternative to non-compliance would likely be to procure a single resource or type that could address deficiencies in multiple hours, rather than multiple resources to cure separate hour deficiencies.<sup>191</sup>

The Commission determines that retaining the existing RA penalty structure, as well as basing RA compliance penalties on the largest hour

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<sup>189</sup> CAISO Reply Comments on LOLE Study, March 22, 2022, at 1.

<sup>190</sup> Reform Report at 18.

<sup>191</sup> *Id.* at 68.

deficiency, is an appropriate penalty mechanism that does not double-penalize LSEs for multiple hour deficiencies. Accordingly, SCE's proposed penalty structure shall apply to the 24-hour framework.

#### **4.6.9. Coordination with CAISO Processes**

Under SCE's 24-hour proposal, LSEs that fail a Commission showing should be "first in line" to receive CAISO backstop costs resulting from showing deficiencies, in addition to Commission penalties.<sup>192</sup> SCE recommends CAISO publicly identify the hour it will test for a deficiency and agree to use the Commission's hourly profile value for solar and wind for that hour, as well as the corresponding load level for that hour. The Commission can provide to CAISO the QC value based on the test hour and CAISO can run its normal on-peak deliverability study and NQC processes. SCE believes CAISO's one-hour deficiency test may need to evolve over time to test multiple hours and recommends the implementation details be developed at a later time.

Several parties, including CalWEA, CLECA, and Hydrostor, support reforming the current deliverability assessment process and expanding the process to consider hours other than just the highest stressed hour.<sup>193</sup> Hydrostor urges CAISO to consider what modest changes to the deliverability study methodology could be addressed in this proceeding or a CAISO stakeholder process, such as CAISO's Interconnection Process Enhancements Initiative. CAISO cautions against adopting proposals that fail to consider the transmission system's ability to deliver generation resources to load and CAISO's critical role

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<sup>192</sup> *Id.* at 18.

<sup>193</sup> CalWEA Comments on Reform Report, March 24, 2022, at 2; CLECA Reply Comments on Reform Report, April 1, 2022, at 2; Hydrostor Comments Reform Report, March 24, 2022, at 5.

in such assessments as the independent system operator and partner in the RA program.<sup>194</sup> CAISO recommends an initial framework or transition period that would not require significant CAISO tariff changes to allow CAISO to complete a stakeholder process and maintain operability of the existing RA framework with CAISO systems.

The Commission recognizes that further development is needed to identify the necessary changes to the CAISO tariff to ensure consistency across the Commission's and CAISO's processes. Parties are directed to discuss and identify necessary changes in the workstreams identified in Section 4.7. We concur with CAISO that changes to the deliverability assessment process should be made in close coordination with CAISO. Given CAISO's role in performing the deliverability assessment, discussion of the deliverability assessment process should first be undertaken in a CAISO stakeholder process prior to the Commission's consideration.

#### **4.6.10. Hourly Load and Resource Trading**

Several parties advocate for allowing hourly obligation trading and resource trading as part of SCE's proposal, including CalCCA, CEDMC, CESA, Joint CCAs, and Shell Energy.<sup>195</sup> These parties generally claim that without the ability to trade hourly obligations and products, it will be difficult for LSEs, particularly small LSEs, to procure portfolios that match their hourly load curve and may result in over-procurement.

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<sup>194</sup> CAISO Comments on Reform Report, March 24, 2022, at 6.

<sup>195</sup> CalCCA Comments on Reform Report, March 24, 2022, at 4; CEDMC Comments on Reform Report, March 24, 2022, at 3; CESA Comments on Reform Report, March 24, 2022, at 9; Joint CCAs Comments on Reform Report, March 24, 2022, at 4; Shell Energy Comments on Reform Report, March 24, 2022, at 9.

Several parties oppose hourly obligation trading and capacity trading, including AReM, CAISO, CLECA, PG&E, and SCE.<sup>196</sup> These parties generally contend that resource trading would be administratively burdensome to track compliance and require additional showings, that keeping RA bundled on an hourly basis is a key feature of the 24-hour framework, and that adding this component would hamper the framework's initial implementation. CAISO voices substantial concerns about the complexity of resource and load trading, as it would impact CAISO's outage, substitution, backstop procurement, and cost allocation processes, as well as create significant implementation challenges.

PG&E highlights that the 24-hour framework allows for portions of a resource to be sold and offers flexibility for how storage is shown, which permits LSEs to match their load shape with procured storage.<sup>197</sup> AReM remarks that LSEs should sell excess capacity that is not needed for certain slices to other LSEs, which is allowed under either proposal.<sup>198</sup> SCE states that it is unclear why CalCCA believes both load and resource trading are needed when the hourly RA load trading sufficiently addresses their concern.<sup>199</sup>

For obligation trading, CLECA, SCE, and SEIA/LSA, support deferring this issue to a later phase once the new framework is implemented.<sup>200</sup> PG&E

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<sup>196</sup> AReM Reply Comments on Reform Report, April 1, 2022, at 2; CAISO Reply Comments on Reform Report, April 1, 2022, at 3; CLECA Comments on Reform Report, March 24, 2022, at 5; PG&E Reply Comments on Reform Report, April 1, 2022, at 7; SCE Reply Comments on Reform Report, April 1, 2022, at 9.

<sup>197</sup> PG&E Reply Comments on Reform Report, April 1, 2022, at 7.

<sup>198</sup> AReM Reply Comments on Reform Report, April 1, 2022, at 2.

<sup>199</sup> SCE Reply Comments on Reform Report, April 1, 2022, at 10.

<sup>200</sup> CLECA Comments on Reform Report, March 24, 2022, at 5; SCE Reply Comments on Reform Report, April 1, 2022, at 10; SEIA/LSA Comments on Reform Report, March 24, 2022, at 7.



comments that a proposal on obligation trading should address key questions, such as whether load trading is consistent with Pub. Util. Code § 380(c) requiring LSEs to maintain capacity to meet its load requirements.<sup>201</sup>

The Commission agrees that a key component of SCE's 24-hour framework is that all RA resource attributes (*i.e.*, system, local RA) and capabilities are bundled across the month. The bundling component ensures alignment with CAISO's existing monthly 24 x 7 must-offer obligation (up to the resource's use-limitations). Bundling also preserves the value of existing contracts by alleviating the need for contract amendments and provides a simpler product to transact than an hourly product.

The Commission observes that allowing hourly resource trading would effectively unbundle the monthly RA product, adding significant complexity to the RA program. As noted by CAISO, allowing resource and hourly load trading has impacts on outage substitution, cost allocation, backstop procurement, and implementation and is not compatible with deliverability and assessing capacity sufficiency. We further agree with PG&E that the 24-hour framework allows LSEs to match their load shapes with storage or other use-limited resources, thereby providing a means for LSEs to meet their 24-hour monthly obligations. Under the 24-hour framework, LSEs are not precluded from transacting or swapping with other LSEs to optimize their positions. For these reasons, we decline to consider hourly resource or load obligation trading for inclusion in the 24-hour framework.

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<sup>201</sup> PG&E Reply Comments on Reform Report, April 1, 2022, at 8.

#### 4.6.11. UCAP

CAISO has been evaluating the UCAP methodology as an RA counting method that would embed forced outage rates into a resource's RA value through a seasonal availability factor approach.<sup>202</sup> The UCAP methodology uses a derating or availability factor informed by certain outage types that impact a resource's unplanned availability, discounting its capacity value for RA valuation purposes. The primary input to calculate UCAP is accurate historical forced outage and derate data. Seasonal availability factors for UCAP determination could be calculated utilizing two seasons: on peak (summer) and off-peak (winter). UCAP values would not be affected by CAISO-approved planned or opportunity outages. CAISO recommends examining how UCAP could fit into a counting proposal and PRM analysis as a complement to a 24-hour framework.

CalCCA, CESA, and MRP observe that there are substantial differences between CAISO's proposed UCAP definitions and processes and those in Energy Division's LOLE study, and that the processes should be aligned if UCAP is developed.<sup>203</sup> CLECA and CalCCA state that if UCAP incorporates forced outage rates, the PRM should be adjusted since it accounts for forced outages.<sup>204</sup> PG&E and SCE recommend deferring consideration of UCAP to a later phase to avoid delaying the initial framework implementation.<sup>205</sup> MRP opposes UCAP

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<sup>202</sup> Reform Report at 50.

<sup>203</sup> CalCCA Comments on Reform Report, March 24, 2022, at 15; CESA Reply Comments on Reform Report, April 1, 2022, at 5; MRP Comments on Reform Report, March 24, 2022, at 17.

<sup>204</sup> CalCCA Comments on Reform Report, March 24, 2022, at 15; CLECA Comments on Reform Report, March 24, 2022, at 6.

<sup>205</sup> PG&E Comments on Reform Report, March 24, 2022, at 6; SCE Reply Comments on Reform Report, April 1, 2022, at 8.

because CAISO has not provided evidence to validate that past forced outages is a reliable indicator of future forced outages.<sup>206</sup>

As discussed in D.21-07-014, the Commission continues to see merit in the UCAP framework and observes that embedding forced outage rates into a resource's RA value would better reflect the resource's contribution to reliability across the 24-hour framework. Embedding forced outage rates may also more effectively penalize RA resources that are not available during stressed system conditions than the current RAIM mechanism. Many parties, however, assert that the UCAP proposal is not ready for implementation.

Considering the breadth of outstanding issues to develop prior to initial implementation of the 24-hour framework, the Commission agrees with parties that consideration of the UCAP framework should be deferred to a later phase of the proceeding. In addition to consideration of UCAP, we note that the December 2, 2021 Scoping Memo expressed the Commission's interest in considering modifications to the RA product that would penalize LSEs if their contracted RA capacity underperforms or is not available for CAISO dispatch due to forced outage.<sup>207</sup>

#### **4.6.12. Elimination of the MCC Buckets and Flexible RA Requirements**

The Commission recently revised the MCC bucket structure in D.20-06-031 and D.21-06-029.<sup>208</sup> The MCC bucket requirements are developed using average monthly summer load duration curves and monthly resource use limitations to prescribe cumulative caps that limit how much LSEs can rely on certain

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<sup>206</sup> MRP Comments on Reform Report, March 24, 2022, at 16.

<sup>207</sup> Scoping Memo, December 2, 2021, at 6.

<sup>208</sup> D.21-06-029 at 27; D.20-06-031 at 58.

resources in meeting monthly RA requirements. The current MCC buckets are reflected in the table below.

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

SCE recommends eliminating the MCC bucket structure, and PG&E supports retaining only the DR bucket.<sup>209</sup> Hydrostor supports retaining the MCC buckets to address multi-day reliability events and until proper valuation of LDES is undertaken.<sup>210</sup> Cal Advocates recommends retaining the MCC buckets as it is unclear whether the proposals and counting methods would fully provide for granular, hourly energy sufficiency.<sup>211</sup>

Full removal of the MCC buckets would eliminate the monthly availability requirements specified in the bucket structure. The Commission is concerned that removal of the MCC bucket structure without careful consideration may result in unintended consequences. For example, DR resources would no longer be required to be available Monday–Saturday, for four consecutive hours between 4:00 and 9:00 PM, and at least 24 hours per month from May–September.

<sup>209</sup> Reform Report at 12, 31.

<sup>210</sup> Hydrostor Comments on Reform Report, March 24, 2022, at 4.

<sup>211</sup> Cal Advocates Comments on Reform Report, March 24, 2022, at 16.

Further, the import RA counting rules adopted in D.20-06-028 are tied to the MCC bucket structure.<sup>212</sup>

Prior to eliminating the MCC buckets, it may be necessary to include some availability requirement for resources with monthly use limitations, particularly for demand response and import resources. For import resources, this could be a requirement to deliver energy for at least four hours during the AAHs from at least Monday through Saturday through the compliance month, consistent with the hours specified in the contract. Likewise, DR contracts could be required to be available Monday - Saturday, for four consecutive hours during the AAHs, and at least 24 hours per month from May - September.

The Commission finds it prudent to carefully evaluate the consequences of removing the MCC buckets under the 24-hour framework to ensure that use-limited resources are available throughout the compliance month period and not over-relied on in meeting the 24-hour requirements. Parties are directed to further discuss and develop a proposal for the elimination of the MCC buckets in the workstreams identified in Section 4.7. These discussions should be coordinated with discussions regarding the valuation of LDES resources.

In addition, SCE recommends eliminating the flexible RA requirements as part of the 24-hour proposal, claiming that the granularity of the 24-hour

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<sup>212</sup> D.20-06-028 at OP 2:

A non-resource-specific import should count towards RA requirements if: (a) the contract is an energy contract with no economic curtailment provisions; (b) the energy self-schedules (or in the alternative, bids in at levels between negative \$150/MWh and \$0/MWh) into the day-ahead and real-time CAISO markets at least during the Availability Assessment Hours throughout the RA compliance month, consistent with the MCC buckets; and (c) the energy must be delivered to the LSE in accordance with the governing contract, consistent with the MCC buckets.

approach directly accounts for resource capabilities and use limitations.<sup>213</sup> PG&E and Calpine support eliminating the flexible requirements, with PG&E stating this should be done in coordination with CAISO, and Calpine arguing that the requirements serve no useful function.<sup>214</sup>

The Commission agrees that the granularity of the 24-hour framework may obviate the need for flexible RA requirements. However, CAISO's current tariff and processes will need to align with removal of these requirements. We find that further discussion is necessary to avoid misalignment or other unintended consequences. As such, we direct parties to discuss and develop proposals on the elimination of the flexible RA requirements in the CAISO coordination workstream identified in Section 4.7.

#### **4.6.13. Hedging**

PG&E submits two hedging proposals previously introduced in Track 3B.2 and provides greater detail on the proposals: a Variable Cost Hedge proposal and a Variable Price Cap Rebate proposal.<sup>215</sup> Under the Variable Cost Hedge proposal, LSEs would develop contracts that tie compensation for capacity to the unit's performance in the energy market on an *ex post* basis. The contract would identify variable operating costs that identify heat rate, variable operations and maintenance costs, and emission costs upfront and require a rebate to the LSE equal to any energy market revenues that exceed these costs. PG&E asserts that the approach works well for natural gas units but could be applied to other resource types. PG&E is testing this approach in its IRP procurements and

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<sup>213</sup> Reform Report at 12.

<sup>214</sup> PG&E Reply Comments on Reform Report, April 1, 2022, at 5; Calpine Comments on Reform Report, March 24, 2022, at 11.

<sup>215</sup> See Reform Report at 83-85.

included this concept as an option in its central procurement entity (CPE) solicitations.

Under the Variable Price Cap Rebate proposal, the mechanism would work the same as the Variable Cost Hedge proposal but instead of a rebate based off the variable energy costs in a contract, the rebate is based off the price cap value. When the LMP for the resource goes above the price cap, a rebate would be paid to the LSE. The rebate amount would be equal to the quantity of the contract multiplied by the difference between the LMP and the price cap value. Outstanding questions include the determination of the price cap level and how broadly the price cap should be applied to an LSE's portfolio.

Vistra states that if the Commission concludes that LSEs may not be adequately hedged from high wholesale prices and that linking hedges through the RA product is the best solution, Vistra recommends introducing an energy settlement option for LSEs to meet their RA requirements, which leverages PG&E's variable cost approach that has been incorporated into its CPE procurement process.<sup>216</sup> LSEs would be required to solicit both RA-only and RA-plus energy settlement but energy price hedging would not be mandated. Vistra notes that rules would need to be established for calculating the variable cost components for the RA with the energy settlement option.

Numerous parties oppose a mandatory hedging requirement in the RA program, including CalCCA, Calpine, CESA, CLECA, IEP, MRP, and Shell Energy.<sup>217</sup> Opponents generally claim that hedging is more linked to energy

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<sup>216</sup> See Reform Report at 86-88.

<sup>217</sup> CalCCA Comments on Reform Report, March 24, 2022, at 13; Calpine Comments on Reform Report, March 24, 2022, at 7; CESA Comments on Reform Report, March 24, 2022, at 8; CLECA Comments on Reform Report, March 24, 2022, at 9; IEP Comments on Reform

*Footnote continued on next page.*

price risks (rather than capacity), that hedging requirements may not be cost-effective, that a hedging requirement is not necessary to implement a slice-of-day framework, and that LSEs are in the best position to choose hedging strategies. Cal Advocates, CLECA, and IEP support considering hedging issues in a later phase.<sup>218</sup> Calpine and Cal Advocates support the Commission gathering information on LSEs' current hedging practices before adopting a requirement, as well as studies of the hedging programs IOUs are obligated to pursue.<sup>219</sup>

As stated in D.21-07-014, the Commission remains concerned with the absence of "a means to ensure that RA is linked with energy bidding behavior in order to balance reliability with minimizing costs to customers."<sup>220</sup> However, we recognize that a broad consensus of parties oppose a hedging requirement at this time. We agree with parties that the issue underlying a potential hedging requirement need further analysis. In D.21-07-014, the Commission authorized Energy Division to request energy hedging data (both physical and financial) from LSEs and report such data to the Commission. Once Energy Division collects and evaluates this data, we authorize Energy Division to submit its analysis into the RA proceeding for consideration of a potential hedging requirement to be incorporated into the 24-hour framework.

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Report, March 24, 2022, at 12; MRP Comments on Reform Report, March 24, 2022, at 19; Shell Energy Comments on Reform Report, March 24, 2022, at 10.

<sup>218</sup> Cal Advocates Comments on Reform Report, March 24, 2022, at 13; CLECA Comments on Reform Report, March 24, 2022, at 9; IEP Comments on Reform Report, March 24, 2022, at 14.

<sup>219</sup> Cal Advocates Comments on Reform Report, March 24, 2022, at 13; Calpine Reply Comments on Reform Report, April 1, 2022, at 2.

<sup>220</sup> D.21-07-014 at 38.



#### 4.6.14. Multi-Year Forward Requirements

IEP/WPTF propose a minimum three-year forward requirement for system RA, similar to the three-year requirement for local RA.<sup>221</sup> IEP/WPTF support a 100 percent system requirement for Years 1 and 2. For Year 3, IEP/WPTF recommend a requirement around 90 percent to ensure the right scarcity signals to marginal suppliers.

Calpine and MRP support multi-year system requirements.<sup>222</sup> Parties that oppose multi-year requirements at this stage include Cal Advocates, CalCCA, CLECA, GPI, and PG&E.<sup>223</sup> These parties generally state that multi-year requirements would delay implementation of a new RA framework and that potential load migration may result in LSE over-procurement. Cal Advocates contends that the likelihood of over-procurement is high as IRP and RPS requirements already require long-term contracts, and notes that nothing prevents LSEs from entering into multi-year contracts today if they choose. CalCCA and PG&E support deferring consideration of multi-year requirements to a later phase to consider interactions with the CPE and to evaluate the impact on LSE procurement and load migration.

The Commission agree with parties that state that load migration may result in the over-procurement of resources and that issues associated with multi-year system requirements would delay implementation of a 24-hour

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<sup>221</sup> Reform Report at 89.

<sup>222</sup> Calpine Comments on Reform Report, March 24, 2022, at 10; MRP Comments on Reform Report, March 24, 2022, at 21.

<sup>223</sup> Cal Advocates Comments on Reform Report, March 24, 2022, at 14; CalCCA Reply Comments on Reform Report, April 1, 2022, at 13; CLECA Comments on Reform Report, March 24, 2022, at 10; GPI Reply Comments on Reform Report, April 1, 2022, at 3; PG&E Reply Comments on Reform Report, April 1, 2022, at 6.

framework. We note that a significant portion of the gas fleet is located in local areas where generators can execute multi-year contracts with either the CPE, or LSEs that serve load in SDG&E's TAC area where there is no CPE. The Commission agrees with parties that point out that LSEs can choose to sign multi-year contracts to meet future RA system needs if they choose. For these reasons, we decline to adopt multi-year system requirements at this time.

#### **4.6.15. 2024 Test Year**

As discussed above, the Commission finds it prudent to consider a 2024 test year for full program implementation in 2025, given the complexities of a new RA framework and to allow additional time for consideration of any potential adjustments.

SCE cautions that if the new framework is not implemented in 2024, LSEs may exceed their MCC bucket limits, particularly buckets 1 and 2, due to the current counting of standalone storage, which will result in LSE deficiencies.<sup>224</sup> SCE recommends a 2024 transition year where LSEs are subject to the current rules plus a change in the MCC buckets to account for storage (*i.e.*, 4-hour and 8-hour storage to count in bucket 4 so long as the LSE can show it can charge the resource).

SCE, CalCCA, and Joint CCAs recommend that in a test year, LSEs be required to make the 24-hour showing as an information-only showing that would be assessed by the Commission but not enforced.<sup>225</sup> NRDC recommends a phased implementation timeline to give participants sufficient time to

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<sup>224</sup> SCE Comments on Reform Report, March 24, 2022, at 13.

<sup>225</sup> SCE Comments on Reform Report, March 24, 2022, at 13; Joint CCAs Comments on Reform Report, March 24, 2022, at 8; CalCCA Reply Comments on Reform Report, April 1, 2022, at 3.

understand and adjust to the new framework.<sup>226</sup> NRDC proposes a 2023 test filing with no penalties assessed and a partial implementation in 2024 with penalties limited to a subset of peak hours of greatest concern. Cal Advocates supports a test year or “shadow compliance” year for 2024, if needed, and notes that further development would be necessary to design the test year and decide what components would be binding.<sup>227</sup>

Given the concerns raised regarding the MCC bucket limits for 2024, we agree with Cal Advocates that further development of the design of a test year (or shadow compliance year) is necessary. Parties are directed to develop proposals for 2024 test year as part of the identified workstreams.

#### **4.7. Process and Schedule for Further Development**

##### **4.7.1. Workstreams**

For the outstanding items to be developed under the 24-hour slice framework, SCE proposes detailed workstreams, summarized below:<sup>228</sup>

(1) Workstream 1: Tools and Profiles:

- a. Tools: RA Resource Master Database, Solar and Wind Profile Master Database, LSE Requirement Database, LSE Showing Tool, and Commission Verification Tool.
- b. Hourly load profiles after the CEC finalizes monthly, 24-hour load shape for each LSE.
- c. Energy Storage profiles to account for losses and multiple cycles.

(2) Workstream 2: Determine PRM and Counting Rules:

- a. Appropriate PRM with single PRM.

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<sup>226</sup> NRDC Comments on Reform Report, March 24, 2022, at 6.

<sup>227</sup> Cal Advocates Comments on Reform Report, March 24, 2022, at 3.

<sup>228</sup> SCE Comments on Reform Report, March 24, 2022, at 6.

- b. Counting rules for hybrid and co-located resources for partially deliverable solar and wind.
  - c. Hourly profiles for wind and solar, including how many profiles for each technology based on variations in technology types and location.
  - d. CAM process and RA allocation to consider availability and capability of CAM-eligible resources and LSEs' load share during those slices.
- (3) Workstream 3: CAISO and Commission Validation and Compliance:
- a. Confirm elements of CAISO and Commission validation and compliance that do not require modification in the near term.
  - b. Identify and resolve administrative changes to the RA program at both CAISO and the Commission (*e.g.*, must-offer reporting, outage substitution).

The Commission finds that SCE's proposed workstreams are a solid starting point for further development of the implementation framework. We modify these workstreams to be consistent with the guidance discussed and determinations made in this decision. Accordingly, the Commission adopts the following workstreams for further development of the 24-hour framework.

- (1) Workstream 1. Develop 24-hour framework compliance tools:
- a. RA Resource Master Database to be coordinated with CAISO.
  - b. LSE Showing Tool (template to be used by the LSE to make its filing to the Commission) and Commission Verification Tool (tool to be used by Energy Division to verify compliance).
  - c. LSE Requirement Database to be coordinated with the CEC. This will utilize outputs generated by the CEC's load forecast proposal, including a dry run filing that may inform any necessary changes.

- d. CAM process and RA allocation to consider availability and capability of CAM-eligible resources and LSEs' load share during those slices.
- (2) Workstream 2. Determine PRM and Counting Rules:
- a. Appropriate exceedance level and/or hourly profiles for wind and solar at technology and location level.
  - b. Counting rules for hybrid, co-located, and LDES resources, as well as development of a UCAP-light (ambient derate) mechanism to be applied to dispatchable resources.
  - c. Elimination of the MCC buckets.
  - d. Test year details.
  - e. Appropriate PRM with single PRM initially for all months and hours informed by LOLE study, including NRDC's calibration tool.
- (3) Workstream 3. CAISO and Commission Validation and Compliance as follows:
- a. Confirm elements of CAISO and Commission validation and compliance that do not require modification in the near term.
  - b. Identify and resolve administrative changes to the RA program at both CAISO and the Commission (*e.g.*, must-offer reporting, outage substitution).
  - c. Elimination of the flexible RA requirements.

#### **4.7.2. Schedule for Further Development**

Several parties propose schedules to further develop the outstanding items in the 3rd and 4th Quarter of 2022.<sup>229</sup> PG&E and SCE recommend a proposed decision on the implementation details in the 1st Quarter of 2023, while

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<sup>229</sup> See, *e.g.*, PG&E Comments on Reform Report, March 24, 2022, at 4; SCE Comments on Reform Report, March 24, 2022, at 12; Cal Advocates Comments on Reform Report, March 24, 2022, at 3; CEERT Comments on Reform Report, March 24, 2022, at 4.

Cal Advocates suggests June 2023 for a decision and CEERT proposes the 3rd Quarter of 2023 for a decision. The Commission finds SCE's proposed timeline to be reasonable, with modifications, as it contemplates workstreams to be developed from July to October 2022, comments on proposals in December 2023, and a proposed decision on additional implementation details in the 1st Quarter of 2023.

Accordingly, the below workstream timeline is adopted, with the caveat that the schedule may be revised depending on the progress made in workshops or as necessary to promote the efficient management and fair resolution of the proceeding. The workstreams and schedule adopted in this decision shall be referred to as Reform Track Phase 2.

<b>Reform Track Phase 2 Schedule</b>	
<b>Milestone</b>	<b>Date</b>
Workstreams 1 - 3 to resolve remaining implementation details and methodologies	July - October 2022
Final proposals from Workstreams 1 - 3 filed and served	November 15, 2022
Opening comments on final proposals	December 1, 2022
Reply comments on final proposals	December 12, 2022
Proposed decision on Reform Track Phase 2	First Quarter of 2023

The Commission does not specify the number of workshops to be undertaken to discuss the three workstreams. We encourage parties that served as co-facilitators during Phase 1 of the Reform Track to continue to co-facilitate the Phase 2 workshops. Parties should work together to arrive at an optimal final proposal that addresses the Commission's guidance and concerns set forth in this decision.

The Commission requests that CAISO and the CEC directly participate in these workshops, particularly on issues that pertain to their direct involvement (e.g., load forecast issues, CAISO validation and compliance), and that CAISO identify any required tariff modifications as early as practicable to allow for full implementation prior to 2025. Energy Division shall be consulted and included throughout the workshop process.

At the conclusion of the workshops, an identified party/parties shall prepare and submit a Workshop Report that provides the final proposals for each workstream (identifying consensus and non-consensus items). The Workshop Report shall be filed and served in the RA proceeding by November 15, 2022. Following the submission of the Workshop Report, parties will have an opportunity to comment.

Within 20 days of the effective date of this decision, parties shall reach agreement and inform the Commission (with service to the service list) of the following:

- (1) The date for the first workshop and placeholder dates for at least two subsequent workshops;
- (2) The scope of issues for each workshop;
- (3) Identified part(ies) to facilitate each workshop; and
- (4) Identified part(ies) to prepare and submit the Workshop Report to the Commission.

When developing the content and schedule for the workshops, parties should consider the order in which the implementation details should be addressed, or if certain issues should be considered jointly.

## **5. 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 \_\_\_\_\_, and reply comments were filed on \_\_\_\_\_ by \_\_\_\_\_.

## **6. Assignment of Proceeding**

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

## **Findings of Fact**

1. CAISO recommended that the existing capacity needed for all local areas is 25,449 MWs for 2023, 23,902 MWs for 2024, and 24,221 MWs for 2025.
2. CAISO recommended system-wide flexible capacity requirements that range from 23,448 MWs in November to 17,971 MWs in July.
3. Modifying the RA measurement hours to align with CAISO's revised AAHs is reasonable.
4. It is appropriate to adjust the hours for MCC buckets 1, 2, and 3 based on revisions to the RA measurement hours.
5. To balance the recognized and urgent need to increase the PRM for 2023 with the acknowledgement that additional LOLE modeling must be undertaken, it is prudent and appropriate to adopt a marginally increased PRM for the 2023 and 2024 RA years that falls within the 15 to 17 percent PRM range initially adopted in D.04-01-050.
6. Energy Division's Scenario D ELCC values for solar and wind resources are the best representation of resources likely to be online for 2023 and are appropriate values to apply to solar and wind resources.
7. It is appropriate for the CEC Working Group to develop long-term recommendations for DR QC counting conventions. Given the short time



remaining, it is more realistic for the CEC Working Group to develop recommendations for the 2025 RA year and beyond.

8. Energy Division's proposal to apply third-party DR testing requirements to all LSEs promotes consistency in testing requirements and maintains a level playing field in the RA market. It is reasonable to apply the requirements beginning for the 2023 RA year, subject to certain exemptions.

9. Energy Division's proposal that DRPs conduct testing in the month with the highest aggregate QC for each sub-LAP is reasonable.

10. SCE's 24-hour slice proposal to reform the current RA program best satisfies the principles and concerns identified in D.21-07-014.

11. Given the complexities of implementing a new statewide RA framework, it is prudent to establish a 2024 test year to allow additional time for implementation and potential adjustments, prior to full implementation in the 2025 RA year.

12. The "worst day" approach is the appropriate method to establish individual LSE hourly load forecasts under the 24-hour slice framework. It is reasonable to apply the CEC's load forecast proposal to the 24-hour framework.

13. PG&E's proposed exceedance methodology is a sufficient means to determine solar and wind profiles that are benchmarked to stressed system conditions.

14. For dispatchable resources, it is reasonable to apply the existing Pmax value as a counting methodology.

15. For use-limited dispatchable resources, it is reasonable to include hourly limits due to noise, pollution or other permit-related limits in a broader set of data that Energy Division makes available on RA units.

16. SCE's storage counting proposal for use of Pmax or UCAP-light (if developed), restricted to daily resource capabilities, is reasonable.

17. SCE's proposal to retain the existing hydro QC methodology and apply the monthly value to all hours is appropriate for the 24-hour framework.

18. PG&E's proposal to retain the existing QC methodology for non-dispatchable resources, with a single value applied to all hours, is a reasonable approach.

19. SCE's proposed QC methodology for imports and PG&E's proposed QC methodology for imports, taken together, are reasonable in ensuring that imports provide a monthly capacity reflective of their monthly use limitations.

20. SCE's proposal to retain the existing compliance and penalty structure is an appropriate penalty mechanism that does not double-penalize LSEs for multiple hour deficiencies.

21. SCE's proposed workstreams, with modifications, are an appropriate starting point for further development of the implementation framework.

### **Conclusions of Law**

1. CAISO's recommended LCR study results for 2023-2025 should be adopted.

2. CAISO's recommended systemwide FCR figures for 2023 should be adopted.

3. Revised RA measurement hours for the spring months of March and April should be adopted.

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

5. A 16 percent PRM should be adopted for the 2023 RA year.

6. A minimum 17 percent PRM should be adopted for the 2024 RA year.

7. Energy Division's Scenario D ELCC values for solar and wind resources should be adopted.

8. The CEC Working Group should continue to develop long-term recommendations on DR QC methodologies for the 2025 RA year, consistent with the adopted Reform Track framework.

9. Energy Division's proposal to apply DR testing requirements to third-party DR under contract with all LSEs should be adopted.

10. Energy Division's proposal to conduct DR testing requirements in the month with the highest aggregate QC for each sub-LAP should be adopted.

11. SCE's 24-hour slice proposed framework should be adopted, with modifications, for further development in workshops. Appendix A should be adopted.

12. The CEC's load forecast proposal to establish individual LSE hourly load forecasts for the 24-hour slice framework should be adopted.

13. PG&E's proposed exceedance methodology should be used to determine wind and solar profiles, with the appropriate exceedance level to be determined as part of workstreams.

14. The existing QC methodology should be retained for dispatchable resources for the 24-hour framework.

15. For use-limited dispatchable resources, hourly limits due to noise, pollution or other permit-related limits should be included in a broader set of data that Energy Division makes available on RA units.

16. SCE's storage counting proposal regarding use of Pmax or UCAP-light (if developed), restricted to daily resource capabilities, should be adopted for energy storage resources under the 24-hour framework.

17. The existing QC methodology should be retained for hydro resources under the 24-hour framework.
18. The existing QC methodology should be retained for non-dispatchable resources under the 24-hour framework.
19. Both PG&E's and SCE's respective QC methodology proposals for import resources should be adopted for the 24-hour framework.
20. SCE's proposal to retain the existing compliance and penalty structure should be adopted.
21. SCE's proposed workstreams for further development of the implementation framework, with modifications, should be adopted.

## **O R D E R**

### **IT IS ORDERED** that:

1. The Commission approves 25,449 megawatts as the existing capacity needed for the Local Capacity Requirement for 2023.
2. The Commission approves 23,902 megawatts as the existing capacity needed for the Local Capacity Requirement for 2024.
3. The Commission approves 24,221 megawatts as the existing capacity needed for the Local Capacity Requirement for 2025.
4. The California Independent System Operator's recommended Flexible Capacity Requirements for 2023 are adopted.
5. The Resource Adequacy (RA) measurement hours are modified to 5:00-10:00 PM for March and April, and 4:00-9:00 PM for all other months. The modified RA hours shall be effective beginning in the 2023 RA compliance year.
6. In adopting Ordering Paragraph 5, the maximum cumulative capacity (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 Monday – Saturday, 4 consecutive hours between 4 PM and 9 PM, and at least 24 hours per month from May – September.	8.3%
1	Monday – Saturday, at least 100 hours per month. For the month of February, total availability is at least 96 hours. January - February, May - December, 4 consecutive hours between 4 PM - 9 PM. March - April, 4 consecutive hours between 5 PM – 10 PM.	17.0%
2	Every Monday – Saturday. January - February, May - December, 8 consecutive hours that include 4 PM – 9 PM. March-April, 8 consecutive hours that include 5 PM – 10 PM.	24.9%
3	Every Monday – Saturday. January-February, May - December, 16 consecutive hours that include 4 PM – 9 PM. March-April, 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. A 16 percent planning reserve margin is adopted for the 2023 Resource Adequacy year.

8. A minimum 17 percent planning reserve margin (PRM) is adopted for the 2024 Resource Adequacy year. 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 loss of load expectation modeling by stakeholders and the Commission.

9. Ordering Paragraph 70 of Decision 21-12-015 provides: “Only costs associated with RA resources in excess of an IOU’s own 15% PRM should be charged to all benefiting customers in the IOU’s service territory via the Cost Allocation Mechanism.” This direction is replaced with “Only costs associated

with RA resources in excess of an IOU's own PRM, as adopted in the Resource Adequacy program, should be charged to all benefiting customers in the IOU's service territory via the Cost Allocation Mechanism."

10. The following Effective Load Carrying Capability values for solar and wind resources are adopted beginning in the 2023 Resource Adequacy year:

2023 ELCC Values		
Month	Solar	Wind
January	0.4%	21.9%
February	3.0%	23.4%
March	3.5%	20.7%
April	4.4%	20.7%
May	6.4%	21.8%
June	13.1%	18.2%
July	14.4%	16.6%
August	12.4%	13.8%
September	11.1%	14.2%
October	7.4%	12.6%
November	5.7%	16.5%
December	3.5%	20.5%

11. The California Energy Commission (CEC) Working Group is requested to continue to develop long-term recommendations for a new demand response (DR) qualifying capacity (QC) methodology, consistent with the Reform Track framework adopted in this decision. The CEC Working Group is requested to develop recommendations that consider the following issues for the 2025 Resource Adequacy (RA) year:

- (a) Whether the proposals that are presented in the CEC's stakeholder process are reasonable and appropriate to determine the QC of DR resources;
- (b) Whether the DR QC methodology reflects the contributions of DR resources to reliability;

- (c) Whether the DR QC methodology is compatible with the new RA framework for the 2025 RA year and beyond;
- (d) Whether the DR QC methodology is transparent and how it could be implemented in a time-efficient manner;
- (e) Whether and to what extent alignment of DR measurement and verification methods in the operational space for the California Independent System Operator market settlement purposes with methods to determine DR QC in the planning space should be achieved, and if so, how;
- (f) Whether, and if so what, enhancements to intra-cycle adjustments to DR QC during the RA compliance year, as adopted in Decision 20-06-031, are feasible and appropriate to account for variability in the DR resource in the month-ahead and operational space; and
- (g) Whether, and if so how, any changes to DR adders should be reflected in DR QC methodology.

The CEC Working Group is requested to submit recommendations into this proceeding by February 1, 2023 for consideration for the 2025 RA year.

12. Third-party demand response (DR) resources procured by all load-serving entities shall be subject to the following testing requirements:

- (a) The DR resource must dispatch for four consecutive hours during the Resource Adequacy (RA) measurement hours in every quarter of the delivery year.
- (b) The test must be done at the resource ID level and all resources within the same sub-Load Aggregation Point must be dispatched concurrently. If qualifying capacity values vary by month, within each quarter, the test shall be done in the month with the highest qualifying capacity for each sub-Load Aggregation Point.

The testing requirement for third-party DR resources shall be effective for the 2023 RA compliance year. The testing requirements do not apply to:

- (1) third-party DR resources procured via investor-owned utility (IOU)

programs, such as the Capacity Bidding Program and Base Interruptible Program, or contracted by an IOU under Commission-approved contracts prior to the effective date of this decision; and (2) third-party DR resources in the 2023 Demand Response Auction Mechanism pilot. This Ordering Paragraph replaces Ordering Paragraph 13 of Decision 20-06-031.

13. The results of test dispatches required of third-party demand response (DR) resources, procured by load-serving entities, shall be submitted as follows:

- (a) The scheduling coordinator shall submit the hourly test results to the DR buyer, DR provider, Energy Division, and the California Independent System Operator by the end of the quarter following the quarter in which the test dispatch occurs.
- (b) Third-party DR providers shall submit the hourly test results in their Load Impact Protocol analysis and reports submitted to the Commission.

This Ordering Paragraph replaces Ordering Paragraph 14 of Decision 20-06-031.

14. Southern California Edison Company's 24-hour slice framework is adopted, with modifications, as outlined in Appendix A. Appendix A is adopted in its entirety. To the extent that the decision contains requirements or guidance for the 24-hour slice framework, in addition to those in Appendix A, the additional requirements or guidance shall be complied with.

15. A 2024 test year shall be considered for the 24-hour framework prior to full program implementation for the 2025 Resource Adequacy year.

16. The California Energy Commission's (CEC) load forecast proposal shall be utilized for individual load-serving entities' hourly load forecasts in the 24-hour framework. Energy Division is requested to conduct a dry run load forecast in



2022 for 2023, in coordination with the CEC, to identify challenges and determine if refinements to the methodology are needed.

17. Pacific Gas and Electric Company's exceedance-based methodology shall be used to determine solar and wind profiles under the 24-hour framework. Parties are directed to continue development of the exceedance methodology to determine the appropriate exceedance level.

18. For dispatchable resources under the 24-hour framework, the existing maximum generating capability value shall apply. Parties are directed to develop an Unforced Capacity Evaluation-light mechanism to apply to dispatchable resources as part of the identified workstreams.

19. For use-limited dispatchable resources under the 24-hour framework, hourly limits due to noise, pollution or other permit-related limits shall be included in a broader set of data that Energy Division makes available on Resource Adequacy (RA) units. Parties and Energy Division are directed to capture use limitations in the RA Resource Master Database, to the extent possible.

20. For energy storage resources under the 24-hour framework, the existing qualifying capacity methodology of maximum generating capability value, restricted to daily resource capabilities, shall apply. Excess capacity must be shown to cover battery capacity with efficiency losses. Parties are directed to develop an Unforced Capacity Evaluation-light mechanism to apply to energy storage resources as part of the identified workstreams.

21. For hydroelectric resources under the 24-hour framework, the existing qualifying capacity methodology shall apply, with monthly single value applied to all hours.

22. For non-dispatchable resources under the 24-hour framework, the existing qualifying capacity methodology shall apply, with a monthly single value applied to all hours, subject to availability constraints.

23. For import resources under the 24-hour framework, the following qualifying capacity counting rules shall apply:

- (a) Resource-specific imports shall use the counting rules applicable to that resource type.
- (b) Non-resource-specific imports shall count based on their contract amount and duration.

24. All use-limited resources shall be subject to a minimum four-hour daily output availability.

25. The existing penalty framework for the Resource Adequacy (RA) program, including the point system adopted in Decision 21-06-029, shall apply to the 24-hour framework for load-serving entities (LSEs) that fail to meet the monthly RA requirements. LSEs shall be penalized based on the hour with the largest deficiency.

26. Once Energy Division collects and evaluates energy hedging data from load-serving entities, as directed in Decision 21-07-014, Energy Division is authorized to submit its analysis into this proceeding for consideration of a hedging requirement to be incorporated into the 24-hour framework.

27. The following workstreams are adopted for further development of the 24-hour framework:

- (1) Workstream 1. Develop 24-hour framework compliance tools:
  - a. Resource Adequacy (RA) Resource Master Database to be coordinated with California Independent System Operator (CAISO).
  - b. Load-Serving Entity (LSE) Showing Tool (template to be used by the LSE to make its filing to the Commission)

and Commission Verification Tool (tool to be used by Energy Division to verify compliance).

- c. LSE Requirement Database to be coordinated with the California Energy Commission (CEC). This will utilize outputs generated by the CEC's load forecast proposal, including a dry run filing that may inform any necessary changes.
  - d. Cost Allocation Mechanism (CAM) process and RA allocation to consider availability and capability of CAM-eligible resources and LSEs' load share during those slices.
- (2) Workstream 2. Determine Planning Reserve Margin (PRM) and Counting Rules:
- a. Appropriate exceedance level and hourly profiles for wind and solar at technology and/or location level.
  - b. Counting rules for hybrid, co-located, and long-duration energy storage resources, as well as development of a Unforced Capacity Evaluation-light (ambient derate) mechanism to be applied to dispatchable resources.
  - c. Elimination of the maximum cumulative capacity buckets.
  - d. Test year details.
  - e. Appropriate PRM with single PRM initially for all months and hours informed by a loss of load study, including National Resources Defense Council's calibration tool.
- (3) Workstream 3. CAISO and Commission Validation and Compliance as follows:
- a. Confirm elements of CAISO and Commission validation and compliance that do not require modification in the near term.
  - b. Identify and resolve administrative changes to the RA program at both CAISO and the Commission (*e.g.*, must-offer reporting, outage substitution).

c. Elimination of the flexible RA requirements.

28. The following workstream schedule is adopted for further development of the 24-hour framework. The schedule may be revised depending on the progress made in workshops or as necessary to promote the efficient management and fair resolution of the proceeding.

<b>Reform Track Phase 2 Schedule</b>	
<b>Milestone</b>	<b>Date</b>
Workstreams 1 - 3 to resolve remaining implementation details and methodologies	July - October 2022
Final proposals from Workstreams 1 - 3 filed and served	November 15, 2022
Opening comments on final proposals	December 1, 2022
Reply comments on final proposals	December 12, 2022
Proposed decision on Reform Track Phase 2	First Quarter of 2023

29. Rulemaking 21-10-002 remains open.

This order is effective today.

Dated \_\_\_\_\_, at San Francisco, California.