STATE OF CALIFORNIA GAVIN NEWSOM, Governor

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 19-11-009:

This is the proposed decision of Administrative Law Judge Debbie Chiv. 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 25, 2020 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)(B).

/s/ ANNE E. SIMON
Anne E. Simon
Chief Administrative Law Judge

AES:gp2
Attachment

Decision **PROPOSED DECISION OF ALJ CHIV Mailed on (5/22/2020)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 19-11-009

DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2021-2023, ADOPTING FLEXIBLE CAPACITY OBLIGATIONS FOR 2021, AND REFINING THE RESOURCE ADEQUACY PROGRAM

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DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2021-2023, ADOPTING FLEXIBLE CAPACITY OBLIGATIONS FOR 2021, AND REFINING THE RESOURCE ADEQUACY PROGRAM

Summary

This decision adopts local capacity requirements for 2021-2023 and flexible capacity requirements for 2021 applicable to Commission-jurisdictional load-serving entities. This decision also adopts refinements to the Resource Adequacy program.

This proceeding remains open.

1. Background

In November 2019, the Commission issued the Order Instituting Rulemaking (OIR) to oversee the Resource Adequacy (RA) program, consider changes and refinements to the program, and establish forward RA procurement obligations applicable to Commission-jurisdictional load-serving entities (LSEs) beginning with the 2021 compliance year. This proceeding is the successor to Rulemaking (R.) 17-09-020, which addressed these topics over the preceding two years. Additional information on the procedural history of this proceeding is set forth in the OIR.

A Scoping Memo and Ruling (Scoping Memo) for this proceeding was issued on January 22, 2020. The Scoping Memo identified the issues to be addressed, and set forth a schedule and process for addressing those issues. In addition to identifying the issues in this proceeding, the Scoping Memo established multiple tracks, with issues falling into Track 1, Track 2, and Track 3.

Track 1 was scoped to consider revisions to the RA import rules. Decision (D.) 19-10-021, issued on October 17, 2019, provided background on the Commission's concerns related to the import rules and affirmed RA import requirements. In D.20-03-016, the Commission granted limited rehearing of

D.19-10-021 in R.17-09-020, the predecessor to this RA proceeding. As stated in the Administrative Law Judge's (ALJ) ruling, issued on March 20, 2020, the scope of limited rehearing overlaps with the scope of issues for Track 1; thus, the record developed in Track 1 of R.19-11-009 has been incorporated into the record of R.17-09-020.[1] As such, Track 1 issues will be addressed in a forthcoming decision issued in R.17-09-020.

In general, Track 2 issues are those that need to be resolved earlier in this proceeding, such as adopting Local Capacity Requirements (LCR) and Flexible Capacity Requirements (FCR). The Scoping Memo also set forth a schedule and process for proposals related to counting conventions that included Working Groups for hydro resources, hybrid resources, and third-party demand response resources. On February 7, 2020, the Commission's Energy Division's proposal on Maximum Cumulative Capacity buckets was filed and served by an ALJ ruling.

Track 2 proposals were filed and served on February 21, 2020 by: Alliance for Retail Energy Markets (AReM); California Energy Storage Alliance (CESA); California Independent System Operator (CAISO); California Efficiency + Demand Management Council (CEDMC), CPower, Enel X North America, Inc. (Enel X), and Leapfrog Power, Inc (Leapfrog) (collectively, the Joint DR Parties); Form Energy, Inc. (Form Energy); OhmConnect, Inc. (OhmConnect); Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E); Shell Energy North America (US), L.P. (Shell); Sunrun Inc. (Sunrun); and Southern California Edison Company (SCE). Energy Division's Track 2 proposal was filed and served by an ALJ ruling. On March 18, 2020, the Commission

[1] ALJ's E-Mail Ruling Setting Process and Schedule for Limited Rehearing of D.19-10-021, issued March 20, 2020, at 4.

granted California Community Choice Association (CalCCA) leave to late-file a Track 2 proposal.

A workshop on Track 2 proposals was held on March 5, 2020. Working Group Reports were filed on March 11, 2020 by: the Hydro Counting Working Group (co-chaired by SCE and CAISO); the Effective Load Carrying Capability (ELCC) Working Group (co-chaired by SCE, Calpine Corporation (Calpine), and East Bay Community Energy (EBCE)); the Hybrid Counting Working Group (co-chaired by SDG&E and CESA); and the Demand Response (DR) Working Group (co-chaired by PG&E, CPower, and the Public Advocates Office (Cal Advocates)).

Comments on the workshop, working group reports, and proposals were filed on March 23, 2020. Comments were received from: American Wind Energy Association (AWEA-CA); AReM; CalCCA; Calpine; CAISO; Cal Advocates; California Wind Energy Association (CalWEA); CESA; Center for Energy Efficiency and Renewable Technologies (CEERT); California Large Energy Consumers Association (CLECA); Center for Community Energy (CCE); Golden State Clean Energy, LLC (GSCE); Middle River Power, LLC (MRP); PG&E; The Protect Our Communities Foundation (POC); SDG&E; Shell; SCE; The Utility Reform Network (TURN); Tesla Inc. (Tesla); and Western Power Trading Forum (WPTF). Several joint comments were submitted by the following parties:

- CEDMC, CESA, CEERT, CPower, Enel X, Leapfrog, OhmConnect, Sunrun, Tesla (collectively, the Joint Distributed Energy Resources (DER) Parties);
- CEDMC, CPower, Enel X, Leapfrog, and OhmConnect (collectively, the Joint DR Parties);
- CESA, CEERT, SCE (collectively, CESA/CEERT/SCE);

- Marin Clean Energy, Pioneer Community Energy, and Sonoma Clean Power Authority (collectively, the Joint CCAs);
- Sierra Club, Union of Concerned Scientists, and California Environmental Justice Alliance (collectively, the Joint Environmental Parties);
- Silicon Valley Clean Energy (SVCE), EBCE, and Monterey Bay Community Power Authority (MBCP) (collectively, SVCE/EBCE/MBCP); and
- Solar Energy Industries Association (SEIA) and the Large-Scale Solar Association (LSA) (collectively, SEIA/LSA).

Reply comments were received on April 2, 2020 from: AReM, AWEA-CA, CAISO, CESA, the City and County of San Francisco (San Francisco), CLECA, Calpine, CalWEA, CEERT, CCE, the Joint DR Parties, Green Power Institute (GPI), MRP, PG&E, POC, SDG&E, SEIA/LSA, SCE, Shell, and Sunrun.

2. Issues Before the Commission

The Scoping Memo identified the following issues as within the scope of Track 2:[2]

1. Adoption of the 2021-2023 Local Capacity Requirements (LCR).
2. Adoption of the 2021 Flexible Capacity Requirements (FCR).
3. Adoption of the 2021 System RA Requirements.
4. Priority Refinements to the Resource Adequacy Program, including:
    a. Modifications to the maximum cumulative capacity (MCC) buckets to address increasing reliance on use-limited resources to meet reliability and needs.
    b. Qualifying capacity counting conventions and requirements for hydro resources, hybrid resources, third-party demand response resources (including load

[2] Scoping Memo at 4.

impact protocols and contract provisions), and potentially other resources.

c. Re-aggregation of the "PG&E Other" area. In D.19-02-022, the Commission disaggregated the "PG&E Other" local area and provided the background for this approach.

d. Changes to the existing penalty structure and waiver process to address potential market power and other issues.

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

All proposals and comments submitted by parties were considered but given the large number of parties and issues, some proposals and comments may receive little or no discussion in this decision. Issues within the scope of the proceeding that are not addressed here, or only partially addressed, may be addressed in Track 3 of this proceeding.

3. Discussion

3.1. 2021-2023 Local Capacity Requirements

In D.06-06-064, the Commission established the local RA program framework and adopted local procurement obligations for 2007. Acknowledging the Commission's role in adopting local procurement obligations, CAISO presented the Commission with three options, each of which reflected different reliability levels driven by transmission grid operating standards that the CAISO must meet. The Commission determined that the local requirements for 2007 should be based on a level of reliability described as "Option 2" in the CAISO's LCR study report:

> <u>Option 2 - Meet Performance Criteria Category C and Incorporate Suitable Operational Solutions</u> - This option represents LCRs and deficiencies associated with "Performance Criteria-Category C" with operational solutions. According to the CAISO's LCR study report, Category C

> describes the system performance that is expected following the loss of two or more system elements expected to happen simultaneously, a condition is referred to as "N-2." By reflecting transmission operational solutions, this option allows for a lower generation requirement. However, long-duration outages would potentially subject load to extended outages.[3]

The Commission determined that Option 2 represented the most appropriate balance of reliability objectives and the costs of attaining reliability. The Commission stated that "[w]hile we expect to apply Option 2 in future years in the absence of compelling information demonstrating that the risks of a lesser reliability level can reasonably be assumed, we nevertheless leave for further consideration in this proceeding the appropriate reliability level for Local [Resource Adequacy requirements] for 2008 and beyond."[4]

D.06-06-064 determined that a study of LCR, performed by CAISO, would form the basis for the Commission's local RA program. CAISO conducts its LCR study annually and the Commission resets local procurement obligations each year after a review of the CAISO's LCR recommendations. A series of subsequent decisions (most recently D.19-06-026) established local procurement obligations for 2008 through 2022 using the same "Option 2 / Category C" reliability criteria presented in CAISO's annual LCR study. In D.19-02-022, the Commission adopted multi-year local RA requirements for a three-year duration to begin for the 2020 compliance year.

This year, CAISO's draft LCR study was received on April 8, 2020, and comments to the draft LCR study were filed on April 17, 2020 by CCE, POC,

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3 D.06-06-064 at 17. Option 1 is equivalent to a N-1 condition and Option 3 relies on installed generation capacity rather than transmission operational solutions to address identified capacity deficiencies. *Id.* at 16-17.

4 *Id*. at 21.

PG&E, and TURN. CAISO's 2021 Final Local Capacity Technical Study (Final LCR Report) was received on May 1, 2020. CCE, PG&E, POC, TURN and SDG&E filed comments to the final LCR study on May 8, 2020. POC, IEP/WPTF, CAISO, and CCE filed reply comments on May 13, 2020.

In both the draft and Final LCR Report, the performance criteria (described in section 1 1.5) used to establish the local procurement obligations changed from prior years. In its Final LCR Report, CAISO states that it conducted a stakeholder process in 2019 to update 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. CAISO held open stakeholder meetings on May 30, July 18, and September 10, 2019 and the Federal Energy Regulatory Commission (FERC) approved CAISO tariff changes to align the LCR criteria with mandatory standards on January 17, 2020, with no stakeholder opposition. CAISO states that the updated LCR criteria are closely aligned with prior requirements, as shown by the relatively small increase (517 MW or 2.2 percent) in overall local capacity requirements between 2020 and 2021.

However, at the local area and sub-area level, the changes in capacity needs are varied. Some local areas and sub-areas have increased requirements while others have decreased requirements, with many smaller sub-areas being eliminated.[5] In particular, the updated criteria resulted in an 1,850 MW increase in the Greater Bay Area local requirement, which represents a roughly 40 percent increase over the previous LCR study.

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5 CAISO Notice of Availability, 2021 Final Local Capacity Technical Study, May 1, 2020, at 2.

The CAISO's recommended 2021-2023 LCR values are summarized in the following table, with the 2020-2022 LCR values provided for comparison.

2021-2023 Local Capacity Requirements			
Local Area Name	**2021**	**2022**	**2023**
Humboldt	130	131	131
North Coast/North Bay	842*	842	840
Sierra	1821*	1834*	1371*
Stockton	596*	596*	642*
Greater Bay	6353	6292	6231
Greater Fresno	1694*	1763*	1832*
Kern	413*	413*	300*
Big Creek/Ventura	2296	2291	1013
LA Basin	6127	6387	6361
San Diego/Imperial Valley	3888	3640	3481
Total	24160	24189	22202
* 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.			

2020-2022 Local Capacity Requirements			
Local Area Name	**2020**	**2021**	**2022**
Humboldt	130	131	131
North Coast/North Bay	742	672	684
Sierra	1764*	1765*	1765*
Stockton	629*	629*	629*
Greater Bay	4550	4511	4473
Greater Fresno	1694*	1698*	1703*
Kern	465*	465*	465*
Big Creek/Ventura	2410*	2576*	2576*
LA Basin	7364	7152*	6243
San Diego/Imperial Valley	3895	4036*	3929
Total	23643	23635	22598

* CAISO note: No local area is "overall deficient". Details about magnitude of deficiencies can be found in the applicable section [of the LCR Report]. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

3.1.1. Comments to CAISO's LCR Study

PG&E questions CAISO's consideration of a double three-phase transformer bank outage at the Metcalf 500 kV substation under the new T-1-1 (i.e., loss of a transformer followed by the loss of second transformer) LCR criteria. PG&E states that the double three-phase transformer bank outage was not previously considered in CAISO's LCR studies. Given "PG&E's layered and robust strategy for addressing the loss of high voltage transformers at the Metcalf substation," PG&E claims that this contingency should not be considered according to NERC standards and FERC Order 693.[6]

TURN raises concerns with the increased LCR for the Greater Bay Area, stating that this is the largest year-to-year MW increase in any local area requirement since enforcement of local requirements in 2007, which will have a

[6] PG&E Comments to CAISO Draft LCR Study at 3.

significant impact on costs for PG&E's customers.[7] TURN encourages the Commission to raise concerns about this increase and to possibly suspend the local procurement requirement for the 2022 and 2023 years, or limit forward procurement in those years to the LCR approved for 2020.[8] TURN also argues for an expedited review of the specific application of CAISO's new local criteria.

POC also raises concerns about the Greater Bay Area LCR evaluation and asserts that the problem arises from CAISO's application of the most stringent standards, which leads to unnecessary and expensive over procurement. POC states that in addition to the NERC and WECC reliability standards, CAISO applies its own "Applicable Reliability Criteria" and that this third set is not necessary.[9] POC encourages evaluation of CAISO's reliability standards to determine if they result in higher transmission costs to ratepayers as compared to the rest of the country.

CAISO responds that based on PG&E's comments, it is determining whether upgraded equipment ratings and/or operating procedures can reduce the 2021 Greater Bay Area need while maintaining consistency with local capacity criteria. CAISO states it will provide an addendum to the 2021 LCR study should it find that updated equipment ratings and operating procedures can effectively reduce the 2021 Bay Area overall need.[10] In reply comments, CAISO notes that at this time it has not identified a transmission solution to

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7 An increase in the local procurement requirement of 1,803 MW times an average price of $40/kW-yr results in additional costs of $72,120,000.

8 TURN Comments to CAISO Draft LCR Study at 1-2.

9 POC Comments to CAISO Draft LCR Study at 2-3.

10 CAISO, Notice of Availability, 2021 Final Local Capacity Technical Study at 3-4.

reduce the Bay Area requirements and therefore, the results of the LCR study are appropriate for setting procurement obligations.[11]

PG&E argues that "the results from this year's LCR process clearly demonstrate that the current timeline for establishing LCR needs can leave very little time for market participants to: (1) evaluate the complexity of the engineering and technical aspects of the local capacity technical study results, (2) consider new analyses, and (3) provide adequate responses for CAISO's consideration."[12] PG&E recommends a local RA working group, led or co-led by CAISO, to address the issues raised and evaluate refinements to the local RA requirements process.

Several parties, including PG&E, POC and SDG&E, comment on CAISO's inclusion of battery storage limits in the Final LCR Study. CAISO states that the "2021 Local Capacity Technical Study includes detailed information regarding the estimated characteristics (MW, MWh, discharge duration) required from battery storage resources to seamlessly integrate in each local area and sub-area."[13] PG&E argues that this new information "could have implications for integrated resource planning procurement and broader state efforts to decarbonize the grid."[14] PG&E recommends a working group to discuss energy storage limitations for local RA.

SDG&E argues that the added storage information warrants evaluating trade-offs between adding new generation versus building new transmission to reduce LCR needs, which has implications on Senate Bill 100 climate goals.

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11 CAISO Reply Comments to CAISO Final LCR Study at 2-3.

12 PG&E Comments on CAISO Final LCR Study at 4.

13 CAISO Reply Comments to CAISO Final LCR Study at 1.

14 PG&E Reply Comments to CAISO Final LCR Study at 3-4.

SDG&E recommends that future assessment of energy storage in the context of LCRs take place in CAISO's annual Transmission Planning Process (TPP). POC supports the new energy storage data for assisting LSEs' understanding of storage needs in local areas but recommends that the storage discussion be reframed to "highlight the path necessary to attain the SB 100 targets of 100% renewable energy."[15]

In reply comments, CAISO agrees there is a need to address energy storage options for local capacity areas and encourages parties to participate in the TPP and LCR stakeholder processes "to further assess opportunities for energy storage resources to replace existing greenhouse gas emitting capacity."[16]

3.1.2. Discussion

The significant increase in LCR need for the Greater Bay Area, driven by the change to local reliability criteria, is concerning, particularly given PG&E's statements that CAISO's consideration of a double three-phase transformer bank outage in the LCR study does not align with NERC and FERC requirements. In D.06-06-064, we determined that "Option 2/Category C" was in the best interest of ratepayers, given the record at the time, and we have continued to adopt local procurement obligations based on that same criteria every year since.

While CAISO states that the revised reliability criteria are intended to align with current mandatory reliability standards developed by NERC and WECC, the Commission has not directly considered this newly adopted local reliability criteria and the costs to ratepayers associated with this dramatic increase in the Greater Bay Area LCR. Therefore, the Commission declines to adopt the

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15 POC Reply Comments to CAISO Final LCR Study at 6.

16 CAISO Reply Comments to CAISO Final LCR Study at 2.

reliability criteria presented in CAISO's Final 2021 LCR Report at this time. We agree with TURN that an expedited review of the specific application of CAISO's new local criteria is necessary. Parties should also have an opportunity to weigh in on the associated impacts of adopting the new reliability criteria, especially with regards to the added reliability and potential costs to ratepayers.

We agree that a local RA working group should be established to evaluate CAISO's updated criteria and other LCR related issues and propose improvements to the local RA requirement process. This working group shall be co-led by CAISO and one of the three investor-owned utilities. The working group shall be established within 15 days of the issuance of this decision and notice of the designated co-leads shall be served on the service list. The working group should focus its immediate efforts on evaluating and providing recommendations on the following issues.

(1) Evaluation of the newly adopted CAISO reliability criteria in relation to NERC and WECC mandatory reliability standards;

(2) Interpretation and implementation of CAISO's reliability standards, mandatory NERC and WECC reliability standards, and the associated reliability benefits and costs;

(3) Benefits and costs of the change from the old reliability criteria "Option 2/Category C" to CAISO's newly adopted reliability criteria;

(4) Potential modifications to the current LCR timeline or processes to allow more meaningful vetting of the LCR study results;

(5) Inclusion of energy storage limits in the LCR report and its implications on future resource procurement; and

(6) How best to address harmonize the Commission's and CAISO's local resource accounting rules.

The local RA working group shall meet as often as necessary to produce a final report that addresses each of the issues listed above and file this report in this proceeding no later than September 1, 2020. We intend to fully understand the local reliability criteria changes in relation to the impact that they have on reliability and cost to ratepayers.

We also encourage CAISO and PG&E to work expeditiously to identify opportunities to reduce the 2021 Bay Area requirements developed in the 2021 Final LCR Study. If CAISO files an addendum in this proceeding prior to July 15, 2020 (when Energy Division plans to issue initial LSE allocations) indicating a reduced LCR for the Greater Bay Area, the Commission authorizes Energy Division to update LSEs' local RA requirements for 2021-2023 to reflect the reduced Bay Area requirement.

To avoid creating a disconnect between setting local RA requirements for 2021 and CAISO's 2021 backstop decisions, it is necessary and prudent to adopt the LCR study results for 2021 for all local areas. Since there was no significant increase in local areas, other than the Greater Bay Area, the 2022 and 2023 LCR study results are adopted for all local areas other than the Greater Bay Area. Given the significant increase to the Greater Bay Area's local requirements, we agree with TURN's proposal that the 2022 and 2023 Greater Bay Area requirements should be based on the 2020 LCR study results. Accordingly, the 2020 LCR study results for the Greater Bay Area are adopted to apply for the 2022 and 2023 Greater Bay Area local requirements.[17] The following table reflects

[17] Consistent with past practice, CAISO's annual LCR study process (that is considered by the Commission in its annual June decision) will review and update the local requirements for 2022 and 2023.

the adopted local reliability requirements, with adjustments for 2022 and 2023 for the Greater Bay Area.

2021-2023 Local Capacity Requirements			
Local Area Name	**2021**	**2022**	**2023**
Humboldt	130	131	131
North Coast/North Bay	842*	842	840
Sierra	1821*	1834*	1371*
Stockton	596*	596*	642*
Greater Bay	6353	4550	4550
Greater Fresno	1694*	1763*	1832*
Kern	413*	413*	300*
Big Creek/Ventura	2296	2291	1013
LA Basin	6127	6387	6361
San Diego/Imperial Valley	3888	3640	3481
Total	24160	24189	22202
* 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.			

3.2. 2021 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 as:

> "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."[18]

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

This year, CAISO notified the Commission that the final Flexible Capacity Needs Assessment for 2021 (FCR Report) would not be submitted until May 15, 2020. An ALJ ruling, issued on April 2, 2020, directed parties to file comments to the final FCR study by May 20, 2020. Comments were filed on May 20, 2020 by POC and CCE. The final FCR Report contains the following figures for 2021, with the 2020 FCR figures provided for comparison.

2021 Flexible Capacity Requirements					
			CPUC		
NOTE: All numbers are in Megawatts	CAISO System Flexible Requirement	CPUC Flexible Requirement	Category 1 (minimum)	Category 2 (100% less Cat. 1 & 3)	Category 3 (maximum)
January	19,596	18,996	7,162	10,884	950
February	18,574	18,031	6,798	10,331	902
March	19,832	19,057	7,185	10,919	953
April	19,088	18,269	6,888	10,468	913
May	17,987	17,145	8,466	7,822	857
June	18,106	17,364	8,574	7,922	868
July	15,725	15,076	7,444	6,878	754
August	15,909	15,214	7,512	6,941	761
September	18,183	17,416	8,599	7,946	871
October	19,102	18,327	6,910	10,501	916
November	19,816	18,964	7,150	10,866	948
December	17,361	16,701	6,297	9,569	835

2020 Flexible Capacity Requirements					
			CPUC		
NOTE: All numbers are in Megawatts	CAISO System Flexible Requirement	CPUC	Category 1	Category 2	Category 3

		Flexible Requirement	(minimum)	(100% less Cat. 1 & 3)	(maximum)
January	18,500	17,646	6,367	10,397	882
February	18,626	18,025	6,504	10,620	901
March	17,700	17,127	6,180	10,091	856
April	17,380	16,662	6,012	9,817	833
May	16,438	15,759	8,291	6,680	788
June	15,108	14,522	7,640	6,156	726
July	12,331	11,812	6,214	5,007	591
August	14,660	13,982	7,356	5,927	699
September	15,958	15,339	8,070	6,502	767
October	17,259	16,698	6,025	9,838	835
November	18,260	17,695	6,385	10,425	885
December	17,810	17,211	6,210	10,140	861

In light of the brief review period available for the Final FCR Report, the FCR figures appear reasonable. Accordingly, CAISO's recommended values set forth in the table above are adopted.

3.3. 2021 System Requirements

One of the Track 2 issues in the Scoping Memo is "[a]doption of the 2021 System RA Requirements." Under that heading, it reads:

> The Commission imposes a system requirement based on the California Energy Commission (CEC) 1-in-2 monthly load forecast, plus a 15 percent planning reserve margin. Absent any alternative proposals, this framework is expected to continue for the 2021 RA program year.[19]

SDG&E proposes a review of the 15 percent planning reserve margin (PRM), noting that the PRM was adopted in D.04-10-050 based on "analysis of then-current market data and forecasts of how the market was expected to evolve due to anticipated increases in renewables, energy efficiency, demand

[19] Scoping Memo at 5.

response and other factors."[20] Considering the changes to the electric grid since that time, SDG&E recommends a review of the PRM to consider whether it appropriately meets grid reliability needs, as well as a review of input assumptions, such as load, generation capacity, and import capability limitations. SDG&E proposes that a loss of load expectation (LOLE) study be conducted to support review of the PRM and a working group perform the study and submit a recommendation in Track 3.[21]

Several parties support this proposal, including AReM, Calpine, MRP, and TURN. TURN supports review of the PRM but states that this may not be enough to assess reliability and that the Commission should also consider "energy sufficiency" of resources and portfolios.[22] SCE prefers that the review be aligned with the CAISO's unforced capacity requirement (UCAP) proposal since the PRM is tied to outages. If adopted, SCE proposes that: (1) the study identify necessary and sufficient components that constitute the PRM, and (2) the study results explicitly state the percentage of PRM corresponding to each of the identified components.[23] SDG&E supports TURN and SCE's recommendations.[24] CalCCA opposes the proposal, stating that the CAISO's UCAP proposal, as well as refining qualifying capacity values, are more critical and likely to be more effective than a LOLE study.[25]

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20 SDG&E Track 2 Proposal at 1 (citing D.04-10-050 at 22).

21 *Id.*

22 TURN Track 2 Comments at 1.

23 SCE Track 2 Comments at 24.

24 SDG&E Track 2 Reply Comments at 2.

25 CalCCA Track 2 Comments at 24.

Given the extensive changes to the grid and the mix of generating resources since the issuance of D.04-10-050, the Commission concurs that it is appropriate to begin review of the PRM and finds SDG&E's proposal for a LOLE study appropriate to support that process. To that end, we authorize Energy Division to facilitate a working group to perform the LOLE study.

3.4. Qualifying Capacity Counting Conventions

The Scoping Memo set forth a schedule and process for Working Groups to develop proposals on qualifying capacity (QC) counting conventions for hydro resources, hybrid resources, third-party DR resources, and potentially other resources. The Commission stated that Working Groups should be co-chaired by at least two representatives, one investor-owned utility (IOU) and one non-IOU representative. Working Groups submitted final reports on consensus and non-consensus items on March 11, 2020.

3.4.1. Methodology for Hydro Resources

Currently, the QC of dispatchable hydro facilities is based on resources' maximum generating capability (Pmax). Initially, SCE and PG&E each proposed changes to the hydro QC methodology designed to more realistically reflect the resource's capacity and energy availability considering variability of water availability from year to year, as well as environmental and regulatory operational constraints.

SCE's initial proposal used the weighted average of three years of availability data to derate the QC of the hydro resource, using availability during the hours of 5:00 a.m. to 9:00 p.m. from May to September to generate an annual capacity number. SCE proposed weighting the most recent year at 50 percent, the prior year at 30 percent, and the driest year in the past ten years at 20 percent. Resources using this methodology would be exempt from Resource Adequacy

Availability Incentive Mechanism (RAAIM) penalties for outages relating to water availability.[26] PG&E initially proposed using an exceedance methodology for derating hydro capacity, in which ten years of bidding and self-scheduling data would determine the 50 percent exceedance level (median) for each month. Calculations would be based on all hours for resources with a 24/7 bidding obligation and the five RAAIM hours for resources with an as-available bidding obligation.[27]

During the Working Group, SCE, PG&E, and CAISO developed a consensus proposal for implementation in 2021. The proposal generates monthly QC values based on the previous ten years of same-month bid-in availability (self-schedules or economic bids). For each month, the historical offered capacity in the Availability Assessment Hours (AAH) is used to calculate a 50 percent exceedance (or median) and a 10 percent exceedance value. The 50 percent value is weighted 80 percent and the 10 percent value is weighted 20 percent to determine the monthly QC value. Mechanical outages would be excluded from the calculation. This is an optional methodology and the CAISO would update its rules to give resources that choose this option an exemption from RAAIM penalties for outages from lack of water availability, but that exemption does not apply to those using existing methodologies.[28]

CAISO, SCE, PG&E, Calpine, Middle River, and CEERT support the Working Group proposal as a reasonable compromise. AReM, Cal Advocates, and CalCCA generally support the proposal but seek consideration of the impact

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[26] Track 2 Hydro Counting Working Group Report (Hydro WG Report), submitted by SCE and CAISO, at 4.

[27] *Id*. at 5.

[28] *Id*. at 7.

of derating hydro resources on the supply stack.[29] Calpine suggests the methodology be mandatory to better reflect actual hydro availability.[30] SCE and PG&E respond that an optional methodology allows resources to reflect facility upgrades or operational changes by allowing them to increase QC values up to Pmax.[31]

The Commission finds that the consensus methodology reflects a reasonable compromise between the initial PG&E and SCE proposals and will provide a more accurate measurement of the capacity that hydro resources can be expected to provide. While this methodology may result in a reduction of capacity on the Net Qualifying Capacity (NQC) list, the listed values will be much more reliable. This methodology should be optional for dispatchable hydro resources so that QC values may be adjusted to account for operational changes or facility upgrades. After publication of the draft NQC list, or during the course of the year, requests may be made to raise NQC values to as much as the generator's Pmax. Additionally, it is reasonable that generators using the voluntary methodology should be exempt from RAAIM penalties for outages related to water availability and we encourage the CAISO to move forward with this change to its rules. Accordingly, the consensus Hydro Working Group proposal is adopted for implementation in 2021.

Energy Division is authorized to employ the adopted methodology in calculations for the 2021 NQC list. Recognizing that it may be challenging to acquire all necessary historical bidding data and information on historical

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[29] AReM Track 2 Comments at 17, Cal Advocates Track 2 Comments at 20, CalCCA Track 2 Comments at 15.

[30] Calpine Track 2 Comments at 7.

[31] SCE Track 2 Reply Comments at 6, PG&E Track 2 Reply Comments at 9.

outages, where data is missing, Energy Division shall base calculations on as many years of data as possible and exclude outages to the extent it is known that they are not related to water availability.

3.4.2. Methodology for Hybrid Resources

3.4.2.1. In-Front-of-the-Meter Hybrid Resources

In D.20-01-004, an interim methodology was adopted for determining the QC value of in-front-of-the-meter (IFM) hybrid resources. The methodology, which applies to a generating resource co-located with a storage project that has charging restrictions related to the Investment Tax Credit (ITC) and a single point of interconnection, uses a "greater of" approach to determine the QC value of the hybrid. The methodology is based on the larger of "either (i) the effective load carrying capability [ELCC] based QC of the intermittent resource or the QC of the dispatchable resource, whichever applies, or (ii) a modified QC of the co-located storage device capped at the maximum amount of expected energy available to charge the storage device."[32]

Several parties offer alternative QC methodologies for IFM hybrid resources. SCE proposes discounting the ELCC value of the renewable generator based on the amount of energy needed to charge the storage device from the renewable so that it is fully charged two hours before the net load peak. The proposal assumes the storage device charges completely from the renewable. If there is installed capacity from the renewable beyond what is necessary to charge the battery, the excess would be utilized to calculate an ELCC value. The storage device would receive a QC value equivalent to Pmax if it can be fully charged from the renewable within the allotted time period. If not, the QC value would

[32] D.20-01-004, Ordering Paragraph 1.

be the energy used to charge the battery (MWh) divided by four. The QC of the combined resource would be the sum of the ELCC of the discounted installed capacity of the renewable and the QC of the storage device.[33]

SEIA/LSA propose that the QC is the sum of the NQCs of the individual components capped the point of interconnection (POI) capacity. This methodology may need to be limited only by: (1) size of the single inverter in DC-coupled configurations, or (2) reduced operational capabilities in winter months for systems where discharge capacity for 4-hour storage is greater than 75 percent of the solar nameplate. Hybrid owners can use up to 25 percent grid power to fill storage (with some loss of the ITC) so owners can determine whether to supply RA up to the full methodology in winter months.[34]

CESA proposes methodologies for three scenarios: (1) for resources under a generator model, derating of the capacity value of on-site generation (i.e., ELCC) and use of an additive approach, capped at the POI; (2) for resources under a non-generating resource (NGR) model with a low storage to generation ratio, the additive methodology, capped at the POI; and (3) for resources under the NGR model with a high storage to generation ratio, derating of the storage's NQC and use of an additive approach, capped at the POI.[35]

CAISO proposes using an exceedance-based methodology for hybrid resources regardless of ITC-related charging restrictions and co-located resources with ITC charging restrictions since an exceedance-based QC value would reflect an individual resource's contribution to grid reliability. Co-located resources

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[33] SCE Track 2 Proposal at 7-8.

[34] Track 2 Hybrid Counting Working Group Report (Hybrid WG Report), submitted by SDG&E and CESA, at 6.

[35] CESA Track 2 Proposal at 6.

without ITC restrictions would receive QC values based on the sum of the QC values of their components capped at the POI. CAISO acknowledges that an exceedance methodology could not be implemented until there is sufficient historical settlement data available.[36]

SDG&E states that an ELCC study is in progress in the Renewables Portfolio Standard (RPS) proceeding, to be completed in Q4 2020, and recommends that study form the basis of a QC methodology. Until that time, SDG&E supports continued use of the adopted interim methodology.[37]

Many parties support SCE's proposal, as least for the near term, including AWEA-CA, CalCCA, CESA, CAISO, Cal Advocates, Calpine, GSCE, MRP, POC, PG&E, SEIA/LSA, and Tesla. The Hybrid Working Group notes a consensus in favor of SCE's proposal as well.[38] Several parties, including PG&E, GSCE, MRP and CAISO, support consideration of an exceedance-based methodology as a longer-term solution.[39] SDG&E opposes the proposals from CAISO, SCE, and CESA, arguing there is no basis for the assumption of a uniform charging rate.[40]

CAISO defines a "hybrid" resource as two resources with a single POI that participate in the market under one resource ID, while "co-located" resources have a single POI but participate in the market under multiple resource IDs. CAISO recommends the Commission use similar terminology because CAISO is proposing must-offer obligations tied to its definitions.[41] The Hybrid Working

[36] Hybrid WG Report at 8, 15.

[37] *Id*. at 5.

[38] *Id*. at 15.

[39] CAISO Track 2 Comments at 14, PG&E Track 2 Comments at 13, GSCE Track 2 Comments at 7, MRP Track 2 Comments at 5.

[40] SDG&E Track 2 Comments at 10.

[41] CAISO Track 2 Comments at 14.

Group Report observes consensus among parties that the Commission and CAISO use similar definitions.[42]

3.4.2.2. Discussion

We agree that the Commission and the CAISO should be aligned on terminology to the extent possible, and find that the CAISO and the Working Group's proposed definition of "hybrid" and "co-located" resources is reasonable. Therefore, the following definitions are adopted: a hybrid resource is "two or more resources (one of which is a storage project) located at a single point of interconnection with a single resource ID." Co-located resources are "two or more resources (one of which is a storage project) located at a single point of interconnection with two or more resource IDs."

Some parties assert that that resources' operating characteristics, not the number of resource IDs, should determine the QC methodology. For example, Tesla states that "the operational behavior of a Hybrid Resource comprised of storage and a [Variable Energy Resource] with a single resource ID is likely to be very similar to that of a similar Co-Located resource, since the economic incentives are similar."[43] In other words, if a hybrid and a co-located resource have identical physical characteristics and charging restrictions, the same QC value should apply to both. The Commission agrees with this view.

There is broad consensus among parties supporting SCE's proposal and we concur that the proposal is a reasonable method for estimating the QC of hybrid and co-located resources. In D.20-01-004, we adopted a conservative interim methodology because we did not have "any operational data or other

[42] Hybrid WG Report at 9.

[43] Tesla Track 2 Comments at 8.

method of determining how a battery should be 'derated.'"[44] SCE's proposal offers an appropriate method for derating the renewable component of the resource.

The Commission believes the exceedance methodology has merit in that it allows an individual resource's charging and dispatch behavior to determine its QC value and may accommodate resources charging partly from the renewable and partly from the grid. However, substantial amounts of historical data are needed for exceedance calculations. Historically, the Commission has utilized three years of historical data to calculate exceedance values. Since the first hybrid and co-located resources are not expected to come online until later this year, and very few are expected to operate in the near term, an exceedance methodology could not be employed for at least several years. We encourage parties and Energy Division to monitor hybrid and co-located resources as they come online and evaluate the appropriateness of the adopted QC methodology as data becomes available. Should an exceedance methodology or alternate methodology be more suitable, parties may propose changes at that time.

Accordingly, SCE's methodology is adopted for valuation of all IFM hybrid and co-located resources planning to access the ITC. It is appropriate to assume that the battery will charge entirely from the renewable generator. The Working Group notes, and we agree, that more discussion is needed on how to treat ITC Limited (75 – 99 percent on-site) charging and non-ITC Limited scenarios as it is unclear how resources will respond to CAISO's must-offer obligation in these cases.[45]

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[44] D.20-01-004 at 8.

[45] *See* Hybrid WG Report at 11.

For each month, we authorize Energy Division to create an energy profile to determine the average number of hours available to charge the storage device from two hours after net load peak until two hours before net load peak. The QC value of the renewable component shall be determined by applying the ELCC percentage to the difference between the renewable's nameplate capacity and the capacity needed to charge the battery at a constant rate over the available charging hours. The QC of the battery component shall be based on the renewable charging energy transferred to the battery in the allotted time period divided by four. The equation below outlines this methodology.

- Total QC = Effective ES QC + Effective Renewable QC
- *Effective ES QC* equals the minimum of:

  (1) The energy (MWh) production from the renewable resource until 2 hours before the net load peak assuming charging is done at a rate less than or equal to the energy storage's capacity. This renewable charging energy is then divided by 4 hours to determine the QC; or

  (2) The QC of the energy storage device.
- *Effective Renewable QC* equals the remaining renewable capacity, net of the capacity required to charge the battery (i.e., *Effective ES QC*), multiplied by the ELCC factor for the month.

3.4.2.3. Behind-the-Meter Hybrid Resources

Sunrun proposes that hybrid (solar-plus-storage) resources behind the customer meter (BTM) have a QC value equivalent to IFM hybrid resources initially. This methodology would apply only to hybrid resources under contract or other obligation to provide capacity to an LSE.[46]

[46] Sunrun Track 2 Proposal at 3.

SEIA/LSA supports this proposal. CESA, CalCCA, and the Joint Environmental Parties note that further development of BTM market participation issues is necessary.[47] Some parties, including SCE, PG&E, Calpine, and Cal Advocates, oppose treating BTM resources as RA resources until fundamental issues are resolved, such as deliverability, metering, must-offer obligations, and how and whether BTM resources are reflected in the load forecast (i.e., incrementality).[48] MRP does not oppose comparable treatment for BTM resources exclusively providing wholesale services but opposes providing access to wholesale revenue streams for resources operating under a net energy metering paradigm.[49] CAISO opposes giving QC values to BTM resources while also treating them as load modifiers which are embedded in the load forecast.[50]

The Commission agrees with parties and the Working Group that numerous issues must be addressed before considering treating BTM resources similarly to IFM resources, including: (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 to net metering tariff and self-generation incentive program to eliminate double compensation, (6) load forecasting and adjustment for BTM

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[47] CalCCA Track 2 Comments at 6, CESA Track 2 Comments at 5, Joint Environmental Parties Track 2 Comments at 8.

[48] *See* Calpine Track 2 Comments at 6, PG&E Track 2 Comments at 15, Cal Advocates Track 2 Comments at 9, SCE Track 2 Comments at 25, Hybrid WG Report at 17.

[49] MRP Track 2 Comments at 13.

[50] CAISO Track 2 Comments at 12.

resources, (7) interaction of such resources with existing BTM resources such as proxy DR, and (8) deliverability determination.

In addition, addressing these issues will require consideration and coordination in multiple Commission proceedings and CAISO stakeholder initiatives. At this time, we deem consideration of specific treatment of BTM resources as premature until broader questions and existing barriers can be been addressed. We note that a BTM resource may continue to participate in the RA program as a DR resource.

3.4.3. Methodology for Effective Load Carrying Capability

Several parties submitted proposals related to ELCC. Calpine proposes applying the existing ELCC methodology to standalone storage resources rather than assuming storage retains its full capacity value. Calpine does not address whether a storage ELCC should be marginal or average but notes that the potential for declining ELCCs under an average approach is an ongoing commercial issue.[51]

Form Energy proposes marginal ELCCs for renewables, standalone storage, and hybrid resources, stating that this approach could send stable investment signals and more accurately capture information about different resources, such as duration. Form Energy proposes assigning a resource its ELCC value at the commercial operation date (COD), which would be constant through the resource's lifetime.[52] SCE similarly proposes a marginal approach involving recalculation of ELCC every six months for the first two years, with resources receiving the prevailing ELCC value as of their COD and retaining that

[51] Track 2 Effective Load Carrying Capability Working Group Report (ELCC WG Report), submitted by Calpine, SCE, and EBCE, at 9.

[52] Form Energy Track 2 Proposal at 4.

value through their lifetime (unless the resource fleet's aggregate ELCC greatly overstates RA value). Resources operational as of January 1, 2020 would retain their existing RA value, unless those values are significantly higher than marginal ELCC.[53]

PG&E proposes differentiating wind and solar ELCC values by region (north or south of Path 26) beginning with the 2022 program year, and differentiating resource ELCCs based on technology types and dispatchability.[54] SCE also asserts that ELCC calculations in RA should be aligned with those in the RPS program, where IOUs must use marginal ELCC values.[55] The ELCC Working Group also recommends prioritization of conversations to align ELCC values in the RA and RPS programs.[56]

Some parties generally support marginal ELCC values, including CalCCA, CCE, MRP, and the Joint Environmental Parties. A few parties support SCE's marginal ELCC proposal or support it with clarifications.[57] Calpine supports marginal ELCC for storage, as proposed by Form Energy.[58] CEERT and PG&E recommend continued discussions to align ELCC values in the RA and RPS programs.[59]

Other parties oppose marginal ELCC values, including AWEA-CA, PG&E, Cal Advocates, and CLECA. Cal Advocates opposes marginal ELCC because

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53 SCE Track 2 Proposal at 10-13.

54 PG&E Track 2 Proposal at 14.

55 SCE Track 2 Proposal at 11-12.

56 ELCC WG Report at 12.

57 *See, e.g.,* CalWEA Track 2 Comments at 1, GPI Track 2 Reply Comments at 3, AReM Track 2 Comments at 13, Calpine Track 2 Comments at 4, SDG&E Track 2 Comments at 15.

58 Calpine Track 2 Comments at 6.

59 PG&E Track 2 Comments at 11, CEERT Track 2 Comments at 5.

only new resources will reflect current fleet reliability and vintaged values will be increasingly inaccurate over time, while AWEA-CA argues that the derate is large and discriminates against new resources.[60] TURN questions the possibility of estimating ELCC for storage (and DR), which cannot be modeled as "must take" resources.[61] Other parties support an average ELCC calculation, including CAISO, Cal Advocates, POC, and SEIA-LSA.

Several parties disagree that marginal ELCC for storage is necessary, arguing generally that average ELCC values for storage will decline significantly in coming years and that ELCC does not reflect the dispatch capabilities of storage resources.[62] Some support continued discussion of the applicability of ELCC to storage.[63]

SCE and Cal Advocates agree with PG&E's proposal to implement more granular ELCC calculations, and AWEA-CA and CLECA similarly recommend focusing on technological and locational refinements instead of marginal ELCC.[64] Cal Advocates states that if marginal ELCC is adopted, locational and technological calculations should be adopted as well. CalWEA supports calculations based on location and technology but suggests first determining whether an ELCC paradigm can account for these differences.[65]

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[60] Cal Advocates Track 2 Comments at 12-15, 17, AWEA Track 2 Comments at 5.

[61] TURN Track 2 Comments at 2.

[62] *See, e.g.,* CLECA Track 2 Comments at 18, MRP Track 2 Comments at 6, SDG&E Track 2 Comments at 17-18, CESA Track 2 Comments at 5-6, CCE Track 2 Reply Comments at 5.

[63] *See, e.g.*, CalCCA Track 2 Comments at 13, CalWEA Track 2 Comments at 2.

[64] Cal Advocates Track 2 Comments at 16, SCE Track 2 Comments at 15-16, CLECA Track 2 Comments at 16, AWEA-CA Track 2 Comments at 6.

[65] CalWEA Track 2 Comments at 2.

The Commission recognizes parties' substantial discussions on ELCC in Track 2. However, based on comments and the Working Group report, there is insufficient consensus among parties to expand or revise the ELCC methodology at this time. We acknowledge the rationale behind support for marginal ELCC values, although it is largely inconsistent with past practice regarding RA qualifying capacity values and requires further development. We authorize Energy Division to further explore a marginal ELCC approach for consideration in this proceeding. The Commission also finds merit in proposals to explore more granular locational and technological ELCC calculations and authorizes Energy Division to conduct studies for consideration in this proceeding.

The Commission shares TURN's concern regarding ELCC values for DR and storage resources, given varying program rules and contractual obligations. For example, it is unclear how effective these values would be if studies assume a certain pattern of bidding and dispatch but resources subsequently bid and dispatch in a substantially different manner. Future proposals to develop ELCC values for DR and storage should include specific proposals regarding the bidding and dispatch that should be assumed for different DR programs and energy storage facilities operating in the market and how these should be modeled in ELCC studies.

3.5. Demand Response Protocols

3.5.1. Testing and Dispatch Requirements

Currently, DR resources are required to be tested once per year for two consecutive hours. Several parties propose changes to DR testing and dispatch requirements. Energy Division proposes testing requirements that all non-emergency DR, except for Demand Response Auction Mechanism (DRAM) resources, be required to dispatch for a four-hour period during the RA measurement hours on three days during peak summer months of July-September. Dispatches could occur through the CAISO market or as test events. Energy Division also proposes that minimum dispatch requirements be consistent with dispatch assumptions associated with the MCC DR bucket.[66]

PG&E proposes a tiered testing requirement for third-party DR. New or changing DR resources would have enhanced requirements of one dispatch per quarter for four hours during the AAHs, which should provide sufficient dispatch or test data to meet minimum operational requirements for DR, "such that load impacts are derived using the appropriate conditions and program design for an RA product and demonstrates typical (not only optimal) resource performance under a variety of weather and other conditions." [67] Stable resources with solid track records would only require one two-hour test per year. All test results would be provided to the Commission and be used to determine QC values.

The Joint DR Parties' revised proposal incorporates PG&E's suggestion that there be tiered testing, but with reduced testing requirements such that one two-hour test would be required per season (in August and in winter months) for incumbent DR providers with well-performing resources. New entrants, DR providers with more than 50 percent growth in their QC, and DR providers with performance of less than 75 percent of their QC must have quarterly two-hour tests or market dispatches. Testing dispatch should be at the resource level and results should be based on average load drop over the two-hour period.[68]

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[66] Energy Division Track 2 Proposal at 5.

[67] PG&E Track 2 Comments at 17.

[68] Joint DR Parties Track 2 Proposal at 4.

CAISO, Calpine and Cal Advocates support Energy Division's proposal. CESA supports PG&E's proposal since it would allow for reduced testing of resources that have demonstrated reliable performance. CAISO prefers market dispatches to tests although it believes that buyers should have the right to conduct unannounced tests.[69] CAISO adds that if there is no market dispatch or test by the buyer, scheduling coordinators should conduct the tests and all test results should be shared with the DR buyer, the Commission, CAISO, and the demand response provider by the scheduling coordinator as the test administrator.

SDG&E argues that QC values will be dramatically overstated if DR providers must have non-coincident (individual) test events with customers and aggregate those relative load drops.[70] SDG&E submits that test events that include all the customers in that DR providers' resource ID, over a four-hour period, during the RA measurement hours during the summer months of July-September, will provide aggregated results more in line with what IOU programs must do.

AReM, CLECA, SCE and the Joint DR Parties oppose minimum dispatch requirements for third-party DR. SCE and Joint DR Parties state that monthly dispatch requirements could result in resources dispatching unnecessarily and uneconomically, potentially increasing ratepayer costs.[71] SCE seeks clarification that SCE's third-party DR would not be subject to the proposed requirements since it is subject to least cost dispatch. SCE adds that the requirements could mean SCE would have to amend its tariff and negate maximization of benefits of

[69] CAISO Track 2 Comments at 9.

[70] SDG&E Track 2 Comments at 12.

[71] SCE Track 2 Comments at 9, Joint DR Parties Track 2 Comments at 10.

these resources since SCE bids to the resources' availability. AReM states that the minimum dispatch requirement only applies to third-party DR with no obligation on IOU DR programs.[72]

3.5.1.1. Discussion

The Commission is persuaded that enhanced testing requirements are needed for third-party DR resources. While we agree with Energy Division that DR resources should demonstrate that they are able to meet the minimum four-hour dispatch requirement for all RA resources, it is inefficient to mandate uneconomic dispatches unnecessarily. We find that PG&E's proposed tiered testing strikes a reasonable middle ground where new and changing resources must demonstrate response over a four-hour period on a quarterly basis but resources that have demonstrated reliable performance will not be subject to the enhanced testing requirement.

However, at this time, there is insufficient record to determine criteria to differentiate between "new and changing resources" and those with established track records. Therefore, we adopt PG&E's proposal with the modification that all third-party DR resources procured by non-IOU LSEs shall be subject to the stricter testing regime. Parties may propose criteria for what constitutes a stable resource and a sufficient track record to qualify for reduced testing requirements in Track 4 of this proceeding.

Accordingly, beginning with the 2021 RA compliance year, all third-party DR resources procured by non-IOU LSEs are required to dispatch for four consecutive hours during the RA measurement hours in every quarter of the delivery year. This requirement can be fulfilled either through a CAISO market

[72] AReM Track 2 Comments at 10.

dispatch or an out-of-market test with a preference for market dispatches. We concur with SDG&E that the tests must be done at the resource ID level and all resources within the same sub-Load Aggregation Point (LAP) must be dispatched concurrently. Performance must be averaged over the four consecutive hours.

As suggested by CAISO, results of the test dispatches must be provided to the DR buyer, Energy Division, CAISO, and the DR provider by the scheduling coordinator. Results must be submitted by the end of the quarter following the quarter in which the test dispatch occurs (i.e., if a dispatch occurs in the first quarter, results must be submitted by the end of the second quarter of the year). In addition, third-party DR providers must include the results of the required tests in their Load Impact Protocols analysis and reports submitted to the Commission. All DR resources belonging to a DR provider for which results are not timely provided will be ineligible for RA showings until the results are submitted. If DR providers are unable to provide results by the appointed date due to inability to access needed data, they may submit documentation showing efforts to acquire the data. Energy Division may allow the provider's capacity to continue to count if it is determined that reasonable efforts were made to comply with reporting requirements.

The Commission finds insufficient record support for adopting a minimum dispatch requirement at this time. However, we will continue monitoring the bidding behavior and performance of DR resources in the market and may adopt dispatch requirements in the future if we conclude that such requirements are needed to ensure that DR resources demonstrate and provide their assumed RA value.

3.5.2. Load Impact Protocols and Alternatives

In D.08-04-050, the Commission determined that all DR programs under Commission jurisdiction were subject to Load Impact Protocols (LIPs). D.09-06-028 established that the LIPs would serve as Net Qualifying Capacity counting rules for all DR resources. In D.16-06-045, the Commission expanded third-party DR through the DRAM pilot program and granted a three-year exemption from LIPs for third-party DR for compliance years 2017-2019. During that period, providers could use contract capacity in lieu of LIPs, to establish RA capacity values. D.19-06-026 noted the expiration of the exemption and that LIPs were once again required for determination of QC values for all DR resources.[73] The exception to this is for resources participating in the DRAM pilot where an alternate counting methodology is in place.

The Joint DR parties request several clarifications to LIPs, including (a) that *ex post* and *ex ante* load impacts be required at the sub-LAP level, (b) that mid-year updates to LIPs be allowed to reflect changes in customer portfolio and performance, and there should be a standard schedule for LIP review, and (c) application of LIPs when there is no historical performance data available.[74] Despite their proposed changes, the DR Parties prefer an alternative QC methodology for third-party DR, claiming that LIPs are not appropriate since program composition is unstable. They also express concern about aspects of the LIP process including confidentiality, financial and administrative burden of LIP analysis, flexibility allowed in LIP analysis, and lack of guidance on enrollment forecasts.

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73 D.19-06-026 at 42, 64.

74 *See generally*, Joint DR Parties Track 2 Proposal.

Instead, the DR Parties propose a methodology similar to that used for the DRAM pilot, where DR providers would provide proposed QC values to Energy Division along with information on program characteristics. Estimated QC would be equal to projected aggregated load multiplied by projected percentage of load impact or reduction. Estimates would be provided for, at minimum, the RA measurement hours and are expected to align with CAISO's AAHs.

Energy Division proposes an alternative to LIPs based on strict backend (*ex-post*) performance and testing requirements enforced via a performance contract between an LSE and third-party DR provider, similar to the SCE LCR DR contracts.[75] A standardized performance contract would be established that included specific elements for: (1) testing, dispatch, and performance requirements, (2) payments and penalties for non-performance, and (3) terms & conditions including bidding requirements. The elements would be determined in the RA proceeding for Commission approval.

Multiple parties oppose an alternative to LIPs. SDG&E and PG&E oppose an alternative, noting that there should be parity in counting rules for DR.[76] SDG&E disagrees with the Joint DR Parties' concerns about the use of LIPs, arguing that LIPs are transparent and not burdensome, straightforward to implement, and provide relatively accurate results.[77] PG&E states that creating rules for one type of resource goes against the Commission's all-source solicitation efforts and notes that in the DRAM program, challenges arose in modifying standard contracts to address problems.[78]

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[75] Energy Division Track 2 Proposal at 7.

[76] *See* PG&E Track 2 Comments at 16.

[77] SDG&E Track 2 Comments at 11.

[78] PG&E Track 2 Comments at 16.

Cal Advocates opposes the DR Parties' proposal because it excludes safeguards adopted in the DRAM proceeding, provides insufficient assurance that claimed capacity will be real and reliable, and because the DRAM guidelines are untested in the auction mechanism. Cal Advocates states that LIPs prescribe the minimum required for accurate short and long-term planning and are necessary if LSEs increase DR in their portfolios.[79] SDG&E and PG&E oppose using the DRAM framework as a starting point as it is untested. CAISO opposes the LIP alternative proposals stating that neither can assess a resource's contribution to reliability.[80]

Some parties support the Joint DR Parties' proposal as an alternative to LIPs or view DRAM as a reasonable starting point.[81]

3.5.2.1. Discussion

The Commission recently reaffirmed that all DR resources, both third-party and IOU-managed (except DRAM resources) must receive QC values based on the application of the LIPs.[82] We are persuaded by parties that state that it is not appropriate to expand the DRAM requirements to all third-party DR at this time since they have not yet been tested within the DRAM pilot program. While we agree with Energy Division that the terms of SCE's LCR DR contracts are rigorous, it would be challenging to apply similar terms to non-IOU LSEs that are not subject to Commission requirements for least cost dispatch and prudent contract management, and the Joint DR parties did not support similar

[79] Cal Advocates Track 2 Comments at 21.

[80] CAISO Track 2 Comments at 7.

[81] *See, e.g.*, CESA Track 2 Comments at 10, CalCCA Track 2 Comments at 14, POC Track 2 Comments at 18, AReM Track 2 Comments at 11.

[82] *See* D.19-06-026 at 42, 64.

contract terms. Consequently, we deem it unnecessary to pursue a significant deviation from the LIP methodology at this time, although improvements or alternatives to the protocols may be considered in the future.

We, however, clarify several aspects of LIPs. First, we concur with the Joint DR Parties that *ex post* and *ex ante* load impacts should be required at the sub-LAP level, and we adopt that requirement here. We also agree with the Joint DR Parties that mid-year updates should be permitted to reflect changes in customer enrollment, although only if the change is reasonably large. During its review of an IOU or third-party LIP filing (prior to the delivery or compliance year), Energy Division will determine the QC value of an IOU or DR provider's resources for the upcoming compliance year(s) based on the projected customer enrollment in the LIP filing after Staff adjustments. Then, in the compliance year, on a biannual basis, Energy Division will update QC values based on the actual customer enrollment volume associated with the provider in the CAISO's Demand Response Registration System (DRRS). LIP results will be updated if QC values vary by more than 20 percent or 10 MW, whichever is greater.

Therefore, the updated QC of a resource applicable during the compliance year would be based on actual realized customer growth or loss which could be higher or lower than assumptions used for the LIP evaluation filed prior to the compliance year. This allows for a more accurate, realistic and reliable QC of the DR resources. Thus, for each resource experiencing growth or attrition, the updated QC value will be calculated as: Updated QC = Actual customer enrollment (from CAISO DRRS) x Average *ex-ante* load impact per customer (from the approved LIP values filed prior to the compliance year).

The load projections from the LIP filing are to be used for the purposes of the year ahead RA compliance fling. However, all RA capacity shown on month ahead RA compliance filings must be based on the updated QC values approved by Energy Division, if applicable.

Next, we clarify the LIP requirements for new resources without historical performance data or existing resources with significantly different expected performance from their prior performance. For these resources, the IOU or the third-party provider must refer to either (a) historical performance for similar resources operated by them in the past or (b) publicly available data that best represents the anticipated performance of such resources consistent with the LIPs for *Ex-Ante* Estimation.[83] The supporting historical performance data must be from resources with similar characteristics including customer class, nature of load, dispatch method, total load, expected percentage load drop, etc. We decline to make additional changes to the LIPs as this time.

3.5.3. Planning Reserve Margin Adder

Energy Division proposes a clarification that the PRM adder for DR QC only applies to system RA because the system RA requirement is based on the load forecast plus a 15 percent PRM while local and flexible requirements are based on the results of CAISO studies and have no associated PRM.[84] AReM and CLECA support Energy Division's clarification.

We concur with Energy Division's clarification that the PRM adder for DR QC applies only to the system RA requirement, and adopt this clarification. Energy Division shall continue to gross up DR resources by the 15 percent PRM adder for counting towards system, but not local or flexible, RA requirements.

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[83] D.08-04-050 at 92-104, Sections 6, 6.1, and 6.2 of "Load Impact Estimation for Demand Response: Protocols and Regulatory Guidance."

[84] Energy Division Track 2 Proposal at 4.

3.5.4. LIP Confidentiality

In D.09-06-028, the Commission determined that the results of LIP evaluations should be made public to the maximum extent possible. However, at that time, the only existing DR was operated by the IOUs and thus, Energy Division currently posts the results of IOU LIP evaluations each year. Energy Division proposes that all LIP results should be posted publicly to the maximum extent allowable, "while protecting customer privacy and market sensitive information of DR providers by adhering to existing Commission policy regarding confidentiality."[85] Energy Division suggests redacting data in instances where there are few customers in an area.

The Joint DR Parties request rules to protect confidentiality of data in the LIPs, such as customer count, per-participant load impact, and current and forecasted portfolio size.[86] They note that although IOUs share this information, third-party providers should not because it could harm competitive positions. The Joint DR Parties propose that third-party DR providers be required to share draft and final LIP reports with only the Demand Response Measurement and Evaluation Committee and Energy Division. CLECA states that customer confidentiality should be maintained when releasing LIP values.[87] The Joint Environmental Parties stress the need for transparency since the public should be able to scrutinize DR.[88]

Other than demand response, the QC for all generating resources is publicly available on the NQC list posted by the Commission and CAISO.

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[85] Energy Division Track 2 Proposal at 15.

[86] Joint DR Parties Track 2 Proposal at 14.

[87] CLECA Track 2 Comments at 12.

[88] Joint Environmental Parties Track 2 Comments at 6.

Similarly, after adoption of the LIPs for DR resources, the results of the evaluations have been publicly available. It is reasonable and necessary to treat all DR resources equally with respect to transparency. Thus, we adopt a requirement that LIP reports and the QC values from a DR provider's LIP results shall be posted publicly to the maximum extent allowable, while protecting customer privacy and market sensitive information of DR providers by adhering to existing Commission policies regarding confidentiality.

3.6. Maximum Cumulative Capacity Buckets

Energy Division, CESA, and Form Energy submitted proposals related to MCC buckets. The current MCC buckets are as follows, adopted in D.12-06-025:

Category	Monthly Availability	Maximum Cumulative Capacity for Bucket and Buckets Above
1	Greater than or equal to the Use Limited Resource (ULR) monthly hours. ULR hours for May through September are, respectively: 30, 40, 40, 60, and 40.	16.2%
2	At least 160 hours	21.7%
3	At least 384 hours	33.8%
4	Unrestricted	100%
DR	No limit, but available at least 24 hours per month	100%

Energy Division recommends revising the existing MCC buckets according to "Option 4b" in its proposal, as follows:[89]

[89] Energy Division MCC Bucket Proposal, issued February 7, 2020, at 8.

Category	Availability	Maximum Cumulative Capacity for Bucket and Buckets Above
DR	Varies by contract or tariff provisions, but must be available during the hours 4 PM – 9 PM	5.3%
1	Monday – Friday, 4 consecutive hours between 4 PM and 9 PM, and at least 40 hours per month from May – September	16.0%
2	Every Monday – Friday, 8 consecutive hours that include 4 PM – 9 PM	22.2%
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)

Option 4b updates the existing MCC buckets by: (a) incorporating 2016-2018 load duration curves, (b) setting a cap on the DR bucket based on assumed ability to dispatch 12 hours per month, (c) requiring that non-DR use limited resources be available at least 40 hours in each summer month, (d) spreading availability for resources in Categories 2 through 4 across an entire month, and (e) requiring that at least 56.1 percent of RA resources be available for all 24 hours during each day of the month.

Energy Division adds that "available" means "able to operate," and that dispatchable resources that provide RA capacity "should be available during the RA planning hours, which are currently hour ending 17 to hour ending 21 (4 PM to 9 PM) for all months."[90]

Form Energy proposes eliminating the MCC buckets, which it considers "too crude a mechanism to guard against energy insufficiency risks." Instead, Form Energy recommends development in Track 3 of "clear definitions of reliability conditions that future LSE portfolios must meet to achieve a reliable 100 percent renewable and zero-carbon grid [and] develop a portfolio assessment

[90] *Id*. at 4.

methodology by which LSEs prove, or the Commission or CAISO confirm, that LSE portfolios can meet [these] reliability conditions."[91] CESA proposes delaying consideration of MCC buckets until Track 3.[92]

Multiple parties support Energy Division's proposal in varying degrees, including CAISO, Cal Advocates, CalCCA, Calpine, MRP, PG&E, SCE, and SDG&E. Cal Advocates states the proposal would prevent LSEs from over-relying on use-limited resources and leaning on other LSEs' portfolios. Cal Advocates also asserts that the modifications would not "bind overall procurement of DR, solar or wind resources based on the Commission's proposed Reference System Plan (RSP) in the IRP proceeding…" and thus, should not increase reliance on natural gas capacity.[93]

CAISO supports "Option 4" in Energy Division's proposal and suggests the MCC buckets align with the portfolio assessment CAISO proposes in its RA Enhancements Stakeholder Initiative. CAISO requests several clarifications, including "clarify[ing] the frequency and number of dispatches it will require from resources in Categories 2 through 4…" and "clarify[ing] that resources in each Category must be both available and dispatchable for all hours that define the category."[94]

PG&E and SCE seek guidance for LSEs on how to assign buckets to resources such as solar and wind, hybrids, DR, and resources with scheduled outages during a given month. PG&E and SCE also request clarification of how the categorizations will be enforced and how to ensure the categorizations match

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[91] Form Energy Track 2 Proposal at 10.

[92] CESA Track 2 Proposal at 11.

[93] Cal Advocates Track 2 Comments at 31-32.

[94] CAISO Track 2 Comments at 1-2, 4.

CAISO's must-offer obligations. PG&E asserts that "availability would be a better metric for calculating [DR] caps than observed dispatch."[95] SCE seeks clarification that only wind and solar resources count as Category 4 resources that are not available at least 24 hours per day, and that DR resources that meet the criteria of other MCC categories should count in those categories.[96]

SCE similarly states that a 5.3 percent cap for DR may be too restrictive and recommends consideration of a second, less restrictive DR bucket to capture resources that are available for more than the proposed minimum of 12 hours, such as resources in SCE's Base Interruptible Program (BIP). CAISO opposes allowing "emergency-triggered demand response resources" like BIP to count in any category other than the DR category because of their use limitations and urges the Commission not to create a second DR category for these programs.[97]

Several parties oppose Energy Division's proposal or recommend consideration in Track 3, including the Joint DER Parties, Joint Environmental Parties, SEIA/LSA, AWEA-CA, CEERT, CLECA, POC, and Sunrun. The Joint Environmental Parties contend that Track 3 would give parties time to address DR concerns and develop an approach that meets reliability, as well as environmental goals.[98] Cal Advocates disagrees with deferring the MCC bucket revisions to Track 3, stating there is no guarantee that modifications would be accomplished in that phase.

95 PG&E Track 2 Comments at 5.

96 SCE Track 2 Comments at 6-7.

97 CAISO Track 2 Reply Comments at 3.

98 Joint Environmental Parties Track 2 Comments at 5.

3.6.1. Discussion

The current MCC buckets allow LSEs to meet up to 100 percent of their RA requirement with DR or storage resources, which do not generate electricity. Energy Division points out that an LSE needs some generating resources in its portfolio because a portfolio of entirely DR or storage would not be able to satisfy an LSE's yearly needs. With respect to DR, Energy Division states that "a substantial amount of currently available capacity is comprised of emergency programs, which do not consistently reduce load each month."[99] Given the increasing reliance on use-limited resources to meet reliability needs and that DR is among the most use-limited resource, modifications to the MCC buckets were scoped as a time-sensitive Track 2 issue.[100] While we recognize that some parties prefer deferring consideration to Track 3, the Commission views updating the MCC buckets and limiting the DR bucket as an urgent reliability issue and declines to defer consideration to a later phase.

We first address the definition of "availability" and how availability applies to the MCC buckets. We appreciate CAISO's clarification that resources in each category should be available and dispatchable for all hours that define the category. Building off this recommendation, we find the following clarification of "availability" to be appropriate in the context of a particular MCC bucket:

(1) Holding aside use limitations or outages, a resource is physically capable of dispatching the entire capacity designated in the given bucket in any and all hours associated with the minimum criteria for that bucket;

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[99] Energy Division MCC Bucket Proposal at 4.

[100] Scoping Memo at 5.

(2) Holding aside use limitations or outages, the resource will economically bid or self-schedule (in the CAISO markets) the entire capacity designated in the given bucket in any and all hours associated with the minimum criteria for that bucket; and

(3) If the resource has use limitations, those limitations would not prevent bidding, self-scheduling, and dispatch during regular, specific hours associated with the minimum criteria for that bucket.

Accordingly, we adopt the above definition of "availability." We note that the ability to bid or self-schedule in the CAISO markets is a necessary but insufficient criterion for categorization in any given bucket – physical capability is also required. For example, holding aside use limitations or outages, a 100 MW resource in Category 2 of the Option 4b proposal must be capable of dispatching all 100 MW for eight consecutive hours (including the hours 4:00 p.m. to 9:00 p.m.) on every weekday of a given month. A non-exhaustive list of reasons why a resource would not qualify for Category 2 includes inability to dispatch for eight consecutive hours and a consistent inability to dispatch during any portion of the 4:00 p.m. to 9:00 p.m. range (*e.g.,* the resource can never operate after 7:00 p.m.).

Given our concerns about the increasing reliance on use-limited resources, we agree that the Option 4b proposal would prevent the over-reliance on such resources to meet reliability needs and minimize LSEs leaning on other LSEs' portfolios. We find the Option 4b proposal to be a reasonable approach, with certain modifications. First, although parties correctly assert that some Category 4 resources have limitations, it is not necessary to identify and assess each particular limitation or to differentiate between regulatory and contractual limitations. Rather, market participants should categorize any individual dispatchable resource according to how its limitations affect its ability to meet the minimum requirements of each MCC bucket. This should also apply to dispatchable storage resources, which vary in their capabilities.

Second, we reaffirm that in-front-of-the-meter wind and solar resources are Category 4 resources. Because wind and solar resources are in Category 4, hybrid and co-located resources that are comprised of wind, solar and/or storage resources should also be in Category 4. Wind, solar, and hybrids and co-located resources with wind and/or solar as the generating component of the combined resource are the only resources in Category 4 that do not have a 24-hour daily availability requirement. However, these resources do not qualify for the 56.1 percent of resources that must be available at all times.

With respect to DR, there is insufficient record at this time to create a second DR bucket. We agree with CAISO that emergency DR programs are in fact limited by the need for an emergency declaration prior to dispatch and that they should therefore be limited to the DR bucket.

With respect to the DR percentage cap, we find that Energy Division's 5.3 percent DR cap is consistent with the RA program's goal of ensuring reliability. We disagree with claims that a 5.3 percent cap would effectively freeze DR at current levels. The 5.3 percent cap represents roughly 2,400 MW of the peak RA requirement of ~45,000 MW, so a 5.3 percent cap would provide for an approximately 30 percent increase over the approximately 1,700 MW of existing levels of DR.

Notwithstanding these observations, the Commission recognizes that numerous measures are adopted in this decision to ensure the effectiveness of DR resources, in addition to efforts in the DR proceeding aimed specifically at improving the performance of DRAM resources. Consequently, it is reasonable and prudent to consider a higher MCC cap to balance out the other efforts and requirements. Parties proposed a wide range of alternative DR caps, ranging from 3.2 – 15 percent.[101]

The Joint DER Parties' proposed approach observes that the cap should reflect the 24-hour-per-month minimum availability requirement of DR, and we find this to be a reasonable approach to setting the initial DR MCC bucket cap. Using the calculus developed in Energy Division's proposal, this approach would result in an 8.3 percent cap, which translates to 3,735 MW of the current peak RA requirement. This cap provides for DR growth of approximately 100 percent over the current levels when accounting for the 15 percent PRM adder. Thus, we conclude that an 8.3 percent DR cap is a prudent approach that balances out the other measures adopted to ensure effectiveness of DR resources, and accordingly, we adopt it here. The Commission intends to monitor and review the effects of this cap on the performance of DR and may adjust it upwards or downwards in the future as warranted.

At this time, the DR cap will apply to all DR resources, including behind-the-meter DR energy storage resources; however, we recognize that these resources – and potentially other forms of economically triggered Proxy Demand Resource (PDR) -- may well be able to meet the technical requirements of Bucket 1. We anticipate further exploration of whether specific DR programs with appropriate, homogeneous operating characteristics should be included in Bucket 1 before the DR bucket constrains development of these resources. We note that the cap on the DR bucket will allow for a doubling of supply-side DR. Thus, we believe a cap will not stifle the growth of DR within any timeframe and

[101] *See, e.g.*, PG&E Track 2 Comments at 5 (recommending 3.2 percent), Joint DER Parties Track 2 Comments at 5 (recommending 15 percent).

will allow sufficient time for an upward revision to the cap if an adjustment is warranted in the future.

Accordingly, we adopt the below table representing the revised MCC buckets. All DR allocations to LSEs through the Cost Allocation Mechanism (CAM) and IOU DR allocations will count towards an LSE's MCC bucket. Energy Division shall notify LSEs of the DR capacity they are being allocated so they are aware how much additional DR may be procured.

ADOPTED MCC BUCKETS

Category	Availability	Maximum Cumulative Capacity for Bucket and Buckets Above
DR	Varies by contract or tariff provisions, but must be available Monday – Friday, 4 consecutive hours between 4 PM and 9 PM, and at least 24 hours per month from May - September	8.3%
1	Monday – Friday, 4 consecutive hours between 4 PM and 9 PM, and at least 40 hours per month from May – September	16.0%
2	Every Monday – Friday, 8 consecutive hours that include 4 PM – 9 PM	22.2%
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)

Finally, although enforcement of MCC buckets is a concern, it is unnecessary to institute additional filing requirements at this time. The Certification of Information on Energy Division's RA filing template covers MCC bucket categorizations, as well as other information in the filings. We authorize Energy Division to request additional documentation (including contracts) to verify LSEs' claims, as well as review bidding data to ascertain how particular resources are operating in the CAISO markets.

3.7. Penalties and Waivers

3.7.1. Shaped Annual System Penalties

Energy Division proposes doubling the penalty for system deficiencies in the five summer months (May to September) as compared to the non-summer months, stating that RA capacity prices in summer months can be much higher than the current penalty price of $6.66/kW-month. In 2018, summer RA prices were almost twice as high as non-summer prices.[102] Energy Division asserts that a penalty price well below the capacity price "is a perverse incentive for LSEs to pay the penalty price rather than cure their deficiencies."[103] The proposal is to shape annual penalty prices such that in the five summer months (May-September), the penalty is $9.40/kW-month and in non-summer months, the penalty is $4.70/kW-month, while the annual penalty remains the same.

Supporters of this proposal include Cal Advocates, MRP, PG&E, and SCE. PG&E states that increasing penalty prices offers greater incentives to procure even though it may increase capacity prices in the short-term.[104] Calpine notes that the current penalty price is too low to attract additional imports, which is often the marginal source of system RA in summer months.[105] MRP supports the proposal but states that LSEs may be incentivized not to procure in shoulder months.[106] SCE states that lowering the penalty for October may be unnecessary

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102 Energy Division Track 2 Proposal at 23 (citing Energy Division's 2018 RA Report, available at: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/2018%20RA%20Report%20rev.pdf).

103 Energy Division Track 2 Proposal at 23.

104 PG&E Track 2 Comments at 6.

105 Calpine Track 2 Comments at 13.

106 MRP Track 2 Comments at 9.

since system requirements are relatively high in October. AReM and Calpine agree that October should be considered a summer month.[107]

AReM and CalCCA oppose changing the penalty price. CalCCA argues that increasing the penalty punishes LSEs making reasonable efforts to comply and enables the increase of market power.[108] AReM states penalty price changes should be deferred until a portfolio optimization approach is developed in the Power Charge Indifference Adjustment's (PCIA) Working Group 3.[109]

The Commission is persuaded that penalty prices below the RA capacity prices may not incentivize LSEs to meet system requirements in summer months. This is particularly true if CAISO does not use its capacity procurement mechanism (CPM) designation to backstop deficiencies (e.g., when the deficiency is small), because otherwise the CPM price will be added to the LSE's penalty price. LSEs that do not procure to meet system RA requirements and simply pay the penalty price are effectively "leaning" on other LSEs. Thus, we find it appropriate to shape the system penalty prices by summer and non-summer months. We also agree that October should be considered a summer month given that the October system requirement has been relatively high. Accordingly, adjusting the proposal to account for October as a summer month, the Commission adopts a shaped system penalty price that is $8.88/kW-month in summer months (May to October) and $4.44/kW-month in non-summer months.

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107 Calpine Track 2 Reply Comments at 3, AReM Track 2 Reply Comments at 6.

108 CalCCA Track 2 Comments at 18.

109 AReM Track 2 Comments at 5.

3.7.2. Other Incentives for Deficient LSEs

Energy Division sought comments on two issues relating to incentivizing deficient LSEs to meet RA requirements. First, Energy Division requested comments on how to incentivize an LSE to procure by the month-ahead filing, when the LSE was deficient in the year-ahead filing, including (a) whether to penalize the portion of the month-ahead deficiency that is redundant to a year-ahead deficiency that is not cured, and (b) how to incentivize LSEs to meet their 90 percent year-ahead requirement and cure deficiencies from the year-ahead process when meeting their 100 percent month-ahead requirement.[110]

Several parties oppose duplicative penalties for year-ahead and month-ahead deficiencies, including Shell, SCE, Calpine, and AReM. Calpine, AReM, and CalCCA recommend reducing the year-ahead penalties for an LSE that successfully fills deficiencies in the month-ahead filing.[111] SCE suggests that for a month-ahead deficiency that is incremental to a year-ahead deficiency, the incremental deficient amount could be penalized.[112]

Second, Energy Division expresses concern regarding LSEs that consistently fail to procure sufficient capacity to meet RA requirements, but continue to simply pay the penalty and lean on other LSEs' procured capacity. Energy Division requested comments on whether it is appropriate to implement escalating penalties or establish a process to remove the LSE from the market.[113]

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[110] Energy Division Track 2 Proposal at 23.

[111] AReM Track 2 Comments at 6, Calpine Track 2 Comments at 14, CalCCA Track 2 Comments at 19.

[112] SCE Track 2 Comments at 21.

[113] Energy Division Track 2 Proposal at 23.

Several parties state that decertifying an LSE is a serious action that requires further discussion, including AReM, SCE, Cal Advocates, MRP, and PG&E. SCE states that consideration must be given to the effect on the POLR, timing and criteria, and size of the applicable deficiency, and PG&E states the mechanism for service continuity for the non-compliant LSE's customers must be evaluated.[114] Cal Advocates states that Energy Division should provide information about the failures to comply, such as the type and number of LSEs failing to procure, the type of RA, the amount, etc.[115] CalCCA supports an escalating penalty only for LSEs that repeatedly fail to demonstrate commercially reasonable efforts through the waiver process or fail to seek a waiver.[116]

With respect to incentives for LSEs deficient in year-ahead filings, the Track 2 comments are a useful start and parties and Energy Division should submit developed proposals in Track 3. With respect to penalties for non-compliant LSEs, the Commission agrees these are serious issues that require thorough discussion and evaluation. However, this is likely not only an RA program-specific concern since an LSE's continued failure to comply with RA requirements may have broader consequences and implications in other Commission proceedings. The Commission encourages further consideration of how to address concerns that LSEs are failing to meet RA and possibly other requirements (*e.g.*, RPS and integrated resource planning).

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[114] SCE Track 2 Comments at 20, PG&E Track 2 Comments at 6.

[115] Cal Advocates Track 2 Comments at 28.

[116] CalCCA Track 2 Comments at 20.

3.7.3. System and Flexible Waivers

In D.19-06-026, the Commission considered a proposal to extend the existing waiver process to system and flexible RA but declined to establish a system and flexible waiver process, concluding that:

> …[T]here remain significant, unresolved issues that require further consideration before allowing such waivers, including potential leaning by LSEs and market power issues. Such market power issues may include potential gaming by generators that may, for example, withhold capacity during more expensive peak months. While we decline to extend the waiver process beyond local RA at this time, the Commission encourages further discussion of these issues through workshops or in a later phase in this proceeding.[117]

In Track 2, CalCCA proposes a system and flexible waiver process, with specific requirements for an LSE to demonstrate, as follows:

(1) Supply was not available to the LSE at a commercially reasonable price before the compliance deadline.

(2) LSE had taken commercially reasonable actions to obtain system or flexible RA, as applicable, as demonstrated by: (a) documented, robust efforts to procure system or flexible RA, as applicable, through bilateral contracts; (b) participation in multiple utility or third-party solicitations; and (c) LSE's issuance of an RFO for RA products before August 31 of the year preceding the compliance year.[118]

CalCCA recommends that Energy Division Staff determine whether an LSE has met the requirements and that if a waiver is not granted, but the LSE cures its deficiency before the compliance deadline, no penalty applies to the cured amount.

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

[118] CalCCA Track 2 Proposal at 7.

Several parties oppose the proposed waiver process, including PG&E, MRP, WPTF, and Calpine. PG&E argues that system and flexible waivers will encourage LSEs to not meet RA obligations, reducing system reliability and allowing LSEs to lean on other LSEs' procurement.[119] MRP and WPTF contend that since the proposal was late-filed days before opening comments, parties cannot discuss the significant unresolved issues required in D.19-06-026.[120] WPTF adds that a waiver process requires rigorous study of supply and demand dynamics that necessitate further exploration.[121]

Calpine opposes the waiver process, stating that "commercially reasonable price" and "commercially reasonable actions" are unacceptably vague standards and should not be left to Energy Division's discretion. Calpine states that a waiver process should establish that LSEs could not obtain capacity at "reasonable" prices, which should include the cost of plausible alternatives, such as developing new resources or attracting additional imports. Calpine suggests a reasonable benchmark could be the cost of new storage to be online by 2021.[122] CalCCA counters that "commercially reasonable" is a well-understood legal term and opposes defining a price as that could have the potential adverse effect of all resources being offered at that price.[123]

The Commission agrees with parties that state that a system and flexible waiver process requires further development and study. We reiterate our statement in D.19-06-026 that there remain "significant, unresolved issues that

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119 PG&E Track 2 Reply Comments at 3.

120 MRP Track 2 Comments at 12, WPTF Track 2 Comments at 3.

121 WPTF Track 2 Comments at 3.

122 Calpine Track 2 Comments at 14.

123 CalCCA Track 2 Reply Comments at 3.

require further consideration before allowing such waivers, including potential leaning by LSEs and market power issues. Such market power issues may include potential gaming by generators that may, for example, withhold capacity during more expensive peak months."[124] Thus, we decline to adopt the proposal.

3.7.4. System Waiver for POLR

SCE states that a limited system and flexible waiver should be adopted for situations where an LSE acting as the provider of last resort (POLR), currently the IOUs, must serve unplanned load. SCE notes that if system and flexible RA capacity prices increase, an LSE has the option to avoid the costs by returning load to the POLR or declining to serve the load. However, that option is not available to the POLR, which "creates an unlevel playing field and the potential for inappropriate and unlawful cost shifting to customers of LSEs acting as the POLR."[125] SCE recommends a limited system and flexible waiver for the POLR for instances in which retail load is: (1) returned to the POLR with insufficient time to meet the RA requirement, or (2) not transferred from the POLR to another LSE as planned as a result of action or inaction by the LSE.[126] SCE notes that the limited POLR waiver should not apply to load that the POLR was forecast to be required to serve.

Several parties support the proposal, including CalCCA, Calpine, Cal Advocates, and MRP. Cal Advocates recommends that the waiver should be through a Tier 2 Advice Letter, like the local waiver process.[127] MRP expresses concern about an LSE that may use this method to abrogate a contract and

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

[125] SCE Track 2 Proposal at 17..

[126] *Id*.

[127] Cal Advocates Track 2 Comments at 34.

recommends that an LSE's supply contract should transfer to the POLR.[128] SCE disagrees, stating that when load is returned to the POLR, the POLR and its customers should not bear cost responsibility and obligations dictated by an LSE's contract. It is also unclear how such a transfer could occur without creating a free option to the seller. SCE states the POLR should issue a solicitation to find supply to meet the incremental RA need for the load that was returned, if feasible.[129] AReM supports the waiver if it is extended to all LSEs with load changes outside of their control, such as load forecast errors.[130]

It is important to ensure that bundled service ratepayers of the POLR are not penalized by actions of other LSEs. Unlike other LSEs in the RA program, the POLR does not voluntarily participate in the retail energy market but is subject to specific requirements as the POLR. SCE's proposal for a limited system and flexible waiver for the POLR is reasonable and accordingly, we adopt it here. We agree that the waiver should be submitted through a Tier 2 Advice Letter.

3.8. Reaggregation of PG&E Other Area

In D.06-06-064, the Commission aggregated six local capacity areas (LCAs) in the PG&E service territory to mitigate market power concerns in those local areas.[131] In D.19-02-222, the Commission disaggregated the "PG&E Other" area to the local capacity areas, concluding that "disaggregation of the "PG&E Other" local area is a necessary first step towards addressing inefficient procurement that may lead to backstop procurement" and disaggregation would "provide

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128 MRP Track 2 Comments at 11.

129 SCE Track 2 Reply Comments at 7.

130 AReM Track 2 Comments at 8.

131 D.06-06-064 at 69. The six local capacity areas - Humboldt, Sierra, Stockton, Greater Fresno, and North Coast, and Kern – were aggregated into "Other PG&E."

useful feedback to the Commission in assessing further disaggregation to the sub-local area level."[132]

In its Track 2 proposal, Energy Division reports that of the 42 LSEs that had 2020-2023 local RA requirements, 20 requested local waivers for the 2020 year-ahead RA filing, a significant increase over prior years. Energy Division notes that one issue was that "the total level of generating capacity available in the Kern, Sierra, and Stockton local areas is very close to the 2020 local requirements for those areas."[133] Another issue was that municipal utilities own 20 percent of capacity in Stockton and 54 percent of capacity in Sierra but since they are non-jurisdictional LSEs and not subject to the disaggregated requirements, there is no incentive to sell their capacity in the PG&E Other LCAs.[134]

AReM, Shell, and Energy Division propose reaggregating the PG&E Other area until a central procurement entity (CPE) is in place. Shell recommends reaggregation for the 2021 RA compliance year until a CPE framework is adopted, and that LSEs receive a blanket waiver for local RA deficiencies in the six LCAs for year-ahead and month-ahead filings for the 2020 compliance year.[135] AReM agrees with Shell's blanket waiver but suggests reaggregation effective September 2020 until a CPE structure is in place.[136]

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132 D.19-02-022 at 30.

133 Energy Division Track 2 Proposal at 2.

134 *Id*.

135 Shell Track 2 Reply Comments at 2.

136 AReM Track 2 Comments at 2.

PG&E does not propose reaggregation but recommends determining that an LSE has fulfilled its RA obligations in the disaggregated LCAs if the LSE demonstrates the following:

(1) The LSE makes the required demonstration as part of the current local waiver process through the Tier 2 Advice Letter for its disaggregated PG&E Other LCA requirements; and

(2) The LSE, in its Year Ahead compliance filing, demonstrates procurement of local RA capacity within the PG&E Other LCAs such that the LSE's collective procurement in the six disaggregated PG&E Other LCAs meets the LSE's collective requirement for the disaggregated PG&E Other LCAs.[137]

Cal Advocates supports PG&E's solution until a CPE is adopted, stating that allowing continued procurement in the disaggregated LCAs allows the Commission to monitor resource availability in those areas.[138]

Some parties oppose reaggregation because doing so will create further market disruption and instability, including Calpine, the Joint CCAs, and San Francisco. San Francisco recommends the CAISO and the Commission study which PG&E Other LCAs have capacity constraints and create an alternative waiver process.[139] The Joint CCAs state that the status quo should remain, given the pending proposed decision on the CPE framework in R.17-09-020.[140]

As noted in comments, a proposed decision is pending in R.17-09-020 that adopts a central procurement entity and framework for the PG&E and SCE

[137] PG&E Track 2 Proposal at 10.

[138] Cal Advocates Track 2 Comments at 27.

[139] San Francisco Track 2 Comments at 3.

[140] Joint CCAs Track 2 Comments at 3.

distribution service areas for the 2023 RA compliance year. The Commission deems PG&E's proposal to be a reasonable balance in recognizing the challenges LSEs face in meeting local requirements for the six LCAs while minimizing market disruption by reaggregating the PG&E Other area. We also agree with Cal Advocates that continued procurement in the disaggregated LCAs gives the Commission insight into the resource availability and constraints in those LCAs. Accordingly, an LSE shall have fulfilled their RA obligations in the six disaggregated LCAs if the following requirements are met:

(1) The LSE makes the required demonstration as part of the current local waiver process through the Tier 2 Advice Letter for its disaggregated PG&E Other local capacity requirements; and

(2) The LSE, in its Year Ahead compliance filing, demonstrates procurement of local RA capacity within the PG&E Other LCAs such that the LSE's collective procurement in the six disaggregated PG&E Other LCAs meets the LSE's collective requirement for the disaggregated PG&E Other LCAs.

3.9. Other Proposals

3.9.1. 3-Year Load Forecast

In D.19-02-022, the Commission adopted multi-year local RA requirements and determined that LSEs' multi-year requirements would be allocated based on load ratio shares from LSEs' Year 1 forecast, concluding that:

> As the Commission is unable to anticipate when new LSEs will form or how load will migrate among LSEs beyond the one-year timeframe, at this point, all LSEs will be allocated local requirements for each of the three forward years based on their load share in the first year resulting from the adopted California Energy Commission (CEC) load forecasting process.[141]

[141] D.19-02-022 at 28.

SDG&E and PG&E propose that LSEs file three-year load forecasts in the year-ahead process, and that Energy Division and the CEC should adjust the forecasts based on the established process and use load ratio shares for each year to allocate that year's local requirements among LSEs.[142] SDG&E states that the Year 1 forecast does not reflect load migration from LSEs that plan to form but have not yet filed an Implementation Plan prior to launch, and load migration from existing LSEs' expanded service anticipated in Years 2 or 3. PG&E similarly argues that using one year's load forecast will likely result in cost shifting, inequities in RA obligations, and potential over-procurement.

Supporters of the proposal include SCE and Cal Advocates. CalCCA voices concern about the accuracy of three-year forecasts considering load migration and how the CEC would resolve individual LSE forecasts that do not sum to the annual requirements, and recommends deferring the proposal to address these issues.[143] Shell opposes the proposal, noting that many LSEs cannot anticipate load migration from one year to the next and ESPs' contracts with direct access customers generally do not extend beyond one year.[144]

The Commission notes that to serve load, an LSE must submit year-ahead load forecasts, which are the signal to any LSE losing load that it is no longer responsible for the departing LSE's RA requirements. In addition, prior to serving load, a CCA must submit an implementation plan that is incorporated into its binding load forecast, but a CCA is not required to receive approval for changes two or three years prior to serving new load. Thus, an LSE can only forecast losing load to another LSE if: (a) the LSE gaining load has submitted an

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142 PG&E Track 2 Proposal at 6, SDG&E Track 2 Proposal at 4.

143 CalCCA Track 2 Comments at 23-24.

144 Shell Track 2 Comments at 4.

associated forecast, and (b) if the LSE gaining load is a CCA, then the CCA reflects that gain in an approved implementation plan. Although three-year forecasts would capture planned expansions that are already included in implementation plans, they would not capture any other major load changes. The Commission is not convinced that requiring three-year forecasts will meaningfully improve the allocation of local RA requirements.

Further, the current one-year forecast adjustment process is very resource- and time-intensive for Energy Division and CEC Staff. Expanding this process to incorporate three years will be overly burdensome, particularly when the Commission is not persuaded that it will result in significant improvements. We decline to adopt this proposal at this time.

3.9.2. Changes to Local Requirements

PG&E asserts that there have been at least two recent instances where the local requirements were established using one set of NQC values, and compliance requirements used a significantly different set of NQC values, which may potentially result in an LSE being required to procure more local capacity in an LCA than is physically available.[145] PG&E proposes that if the final NQC values of the existing supply in an LCA are lower than what the CAISO studied, Energy Division should be permitted to lower the local RA requirements. PG&E proposes a working group (co-led by the CAISO) to be established in Track 3 to evaluate the issues related to the disconnect between the CAISO's local requirements study and the RA program.

A few parties support this proposal, including AReM, SCE, Calpine, and Cal Advocates. CAISO opposes the proposal because it would reduce local

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[145] PG&E Track 2 Proposal at 7.

capacity area reliability. CAISO states that under the schedule developed by the CAISO, Commission, and the CEC, the CAISO must first establish local capacity requirements and allocate to the Commission and non-jurisdictional LSEs, before finalizing NQC values for the next year, which can result in minor changes in NQC values. Further, the CAISO tariff does not allow for changes in local requirement responsibilities after the assignment process, which is designed to protect buyers and sellers in RA contracts. To implement this proposal, CAISO states that Energy Division would also have to increase local requirements if NQC values increase in an area that used to be deficient.[146]

Based on the CAISO's comments, PG&E's proposal is not implementable at this time. The Commission will continue to address this issue through the local waiver process.

3.9.3. Local RA Working Group

In D.19-06-026, the Commission directed Energy Division to establish a working group to "evaluate improvements and refinements prior to the development to the 2021-2023 local RA requirements."[147] This was based on PG&E's proposal to establish a working group "to examine the relationship between local RA requirements, RA resource obligations, changes to NQC in forward years, how RA performance is assessed, and how local RA backstop procurement occurs or does not occur from uncured deficiencies."[148] Energy Division held a working group meeting on this topic on September 5, 2019.

PG&E offers a version of its previous proposal, stating that if a full central procurement model is not adopted, a working group should address issues that

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146 CAISO Track 2 Reply Comments at 15.

147 D.19-06-026 at 8.

148 *Id.*

result from the disconnect between the CAISO's local RA program and the Commission's RA program. If a full procurement model is adopted, PG&E proposes a limited working group on issues that remain to be addressed under this model. PG&E recommends that any working group should consider non-jurisdictional LSEs that seem unwilling to provide RA capacity to the market.[149]

We anticipate that stakeholders will benefit from an organized working group process to address LCR issues that remain after the Commission issues a decision on a central procurement framework. As discussed above in Section 3.1, a working group will be established to address LCR-related issues. Accordingly, the working group established in Section 3.1 shall also address LCR issues that remain after the Commission issues a decision regarding central procurement in R.17-09-020.

3.9.4. EFC of Storage

In D.14-06-050, the Commission adopted QC and effective flexible capacity (EFC) values for storage resources, which is defined as the MW at which the resource can discharge for four hours, called PmaxRA. The adopted EFC value for bi-directional storage "was capped at the greater of the net qualifying capacity (NQC) value or (NQC-PminRA) where PminRA was defined as the height of a rectangle where the base is 1.5 hours of discharge and the area is the battery's available energy for dispatch in MWh."[150] Energy Division states that the current methodology assigns a 3 MW bi-directional battery an EFC of either 11 MW or 19 MW, which it views as significantly overvaluing the flexible capacity of bi-directional storage.

[149] PG&E Track 2 Proposal at 10.

[150] Energy Division Track 2 Proposal at 11.

Energy Division proposes capping both PminRA and PmaxRA at the QC value of a 4-hour dispatch, which would equate to an EFC value of twice the QC value. This assumes the device fully charges over 1.5 hours and fully discharges over 1.5 hours. The cap of 2x QC would apply to bi-directional storage with both a Pdemandmin and Psupplymin of zero, meaning "they can ramp continuously up to and down from 0 MW." Where the storage device cannot ramp continuously over the full range of the device's capacity, the cap in either direction "would be the difference between PminRA and Pdemandmin or Psupplymin respectively."[151]

CalCCA and MRP support the proposal, stating that the current methodology leads to a counterintuitive result.[152] SCE requests clarification of how Pdemandmin and Psupplymin are defined.

The Commission finds Energy Division's proposal to be reasonable and accordingly, adopts the following requirements. For bi-directional storage, PmaxRA shall remain capped at NQC and PminRA shall be capped at -NQC.

- If Psupplymin and Psupplymax = 0, then EFC = PmaxRA – PminRA.
- If Psupplymin and Psupplymax ≠ 0, then EFC = (PmaxRA - Psupplymin) – (PminRA - Pdemandmin).

The definitions of Pdemandmin and Psupplymin, as adopted in D.14-06-050, shall apply.[153]

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[151] *Id*. at 12.

[152] CalCCA Track 2 Comments at 7, MRP Track 2 Comments at 10.

[153] *See* D.14-06-050, Appendix B at B-11:

> $\text{Psupply}_{\text{min}}$ – a positive number representing the minimum amount of discharging or load curtailment that is sustainable for three or more consecutive hours (for example, the minimum amount of DR that may be dispatched); does not apply to resources with only

Footnote continued on next page.

4. Comments on Proposed Decision

The proposed decision of ALJ Chiv in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _________, and reply comments were filed on _________ by _________.

5. Assignment of Proceeding

Liane M. Randolph is the assigned Commissioner and Debbie Chiv is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The CAISO's recommended 2021 LCR values for the Greater Bay Area local area increased by 1,803 MW from the 2020 values adopted in the prior year's 2020 LCR study.

2. The Commission has not directly evaluated CAISO's updated criteria used to establish local procurement requirements and the costs associated with the large increase in local procurement requirements in the Greater Bay Area.

3. For all local areas, it is prudent to adopt CAISO's recommended LCR study results for 2021 to avoid a disconnect between the 2021 local RA requirements and CAISO's 2021 backstop decisions.

negative operating ranges, and may be zero for resources that do not have physically or programmatically-constrained minimum output levels.

$\text{Pdemand}_{\text{min}}$ – a negative number representing the smallest magnitude of charging or load increase that is sustainable for the duration required in calculating EFC (for example, minimum pump loads); does not apply to resources with only positive (discharging or load curtailment) operating ranges, and may be zero for resources that do not have physically or programmatically-constrained minimum charging/load increase levels.

4. For all local areas, other than the Greater Bay Area, CAISO's recommended 2022 and 2023 LCR study results are reasonable, given that there are no significant increases in local procurement requirements.

5. For the Greater Bay Area, TURN's proposal to apply the 2020 LCR study results to the 2022 and 2023 Greater Bay Area requirements is reasonable.

6. It is appropriate to establish a working group to evaluate CAISO's updated criteria and other LCR related issues and propose improvements to the local RA requirement process.

7. CAISO's recommended system-wide flexible capacity requirements range from 15,076 MW in July to 19,057 MW in March.

8. It is appropriate to begin reviewing the PRM adopted in D.04-10-050.

9. The Hydro Working Group's consensus proposal for the QC of hydro resources reflects a reasonable compromise.

10. There is a consensus among parties in favor of SCE's proposal for estimating the QC of in-front-of-the-meter hybrid and co-located resources, as well as in favor of aligning the Commission's and CAISO's definitions for hybrid and co-located resources.

11. PG&E's proposal for tiered testing of third-party DR resources strikes a reasonable middle ground between proposals, with modifications.

12. It is appropriate to make clarifications to the LIP process.

13. To promote transparency and treat all DR resources equally, it is reasonable to require LIP reports and the QC values from a DR provider's LIP results to be posted publicly.

14. It is necessary to clarify the definition of "availability" in the context of a particular MCC bucket.

15. Energy Division's Option 4b proposal to revise the MCC buckets is a reasonable approach, with modifications.

16. It is prudent to consider a higher DR cap given the numerous measures adopted to ensure the effectiveness of DR resources. The Joint DER Parties' proposed approach is reasonable to set the initial DR cap.

17. Penalty prices set below the RA capacity prices may not incentivize LSEs to meet system requirements in summer months. It is reasonable to shape system penalty prices by summer and non-summer months and to include October as summer month.

18. A limited system and flexible waiver for the POLR is reasonable.

19. PG&E's proposal for the disaggregated PG&E Other LCAs reasonably balances the challenges LSEs face in meeting local capacity requirements while minimizing market disruption of reaggregating the PG&E Other area.

20. Energy Division's proposal to modify the EFC values for storage resources is reasonable.

21. Stakeholders will benefit from a working group to address LCR issues that remain after a decision on a central procurement framework is adopted in R.17-09-020.

Conclusions of Law

1. For all local areas, CAISO's recommended LCR study results for 2021 should be adopted. For all local areas, other than the Greater Bay Area, CAISO's recommended 2022 and 2023 LCR study results should be adopted.

2. For the Greater Bay Area, the 2020 LCR study results should be adopted to apply to the 2022 and 2023 Greater Bay Area requirements.

3. A working group should be established to evaluate CAISO's updated criteria and other local requirement issues and propose improvements to the local RA requirement process.
4. CAISO's recommended systemwide FCR figures for 2021 should be adopted.
5. A working group should be established to perform a LOLE study to support review of the PRM.
6. The Hydro Working Group's consensus proposal should be adopted as an optional methodology for dispatchable hydro resources.
7. SCE's proposal for valuation of the QC of IFM hybrid and co-located resources should be adopted. The Hybrid Working Group's proposed definitions for hybrid and co-located resources should be adopted.
8. PG&E's tiered testing requirements for third-party DR resources should be adopted, with modifications.
9. The LIP reports and QC values from a DR provider's LIP results should be publicly available, while protecting customer privacy and market sensitive information.
10. Energy Division's Option 4b proposal to revise the MCC buckets should be adopted, with modifications. An 8.3 percent cap on DR resources should be adopted.
11. A shaped system RA penalty price by summer and non-summer months should be adopted.
12. A limited system and flexible waiver for the POLR should be adopted.
13. PG&E's proposal for addressing the PG&E Other LCAs should be adopted.
14. A modification to the EFC values for storage resources should be adopted.

O R D E R

IT IS ORDERED that:

1. For all local areas, the recommended Local Capacity Requirements for 2021 are adopted.

2. For all local areas, other than the Greater Bay Area local area, the 2022 and 2023 Local Capacity Requirements are adopted.

3. For the Greater Bay Area local area, the 2020 Local Capacity Requirement study results are adopted to apply to the 2022 and 2023 Local Capacity Requirements, as set forth in the table in Section 3.1.

4. The reliability criteria presented in the California Independent System Operator's Final 2021 Local Capacity Requirement Technical Study is not adopted at this time.

5. A working group shall be established within 15 days of the issuance of this decision to evaluate the California Independent System Operator's (CAISO) updated criteria used to establish local procurement obligations and other local requirement issues, and propose recommendations to the local Resource Adequacy requirement process. The working group shall be co-led by the CAISO and one of the investor-owned utilities. Notice of the designated co-leads shall be served on the service list in this proceeding.

6. The working group shall file a report in this proceeding no later than September 1, 2020 that provides recommendations on the following issues:

    (a) Evaluation of the newly adopted California Independent System Operator (CAISO) reliability criteria in relation to the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) mandatory reliability standards;

(b) Interpretation and implementation of CAISO's reliability standards, mandatory NERC and WECC reliability standards, and the associated reliability benefits and costs;

(c) Benefits and costs of the change from the old reliability criteria "Option 2/Category C" to the CAISO's newly adopted reliability criteria;

(d) Potential modifications to the current Local Capacity Requirement (LCR) timeline or processes to allow for more meaningful vetting of the LCR study results;

(e) Inclusion of energy storage limits in the LCR report and its implications on future resource procurement; and

(f) How best to address harmonize the Commission's and CAISO's local resource accounting rules.

The working group shall also address LCR-related issues that remain after the Commission issues a decision regarding central procurement in Rulemaking 17-09-020.

7. If the California Independent System Operator files an addendum in this proceeding prior to July 15, 2020 indicating a reduced Local Capacity Requirement for the Greater Bay Area local area, Energy Division is authorized to update load-serving entities' local Resource Adequacy requirements for 2021 - 2023 to reflect the reduced Greater Bay Area requirement.

8. California Independent System Operator's recommended Flexible Capacity Requirements for 2021 are adopted.

9. Energy Division is authorized to facilitate a working group to perform a loss of load expectation study to support review of the planning reserve margin.

10. The qualifying capacity (QC) methodology for dispatchable hydroelectric resources is adopted as an optional methodology, as follows:

(a) For each month, Energy Division shall use ten years of historical data for capacity offered in the Availability Assessment Hours during that month to calculate a 50 percent (or median) exceedance value and a 10 percent exceedance value.

(b) Energy Division shall weight the 50 percent exceedance value by 80 percent and the 10 percent exceedance value by 20 percent to calculate the monthly QC value. Mechanical outages will be excluded from the calculation.

11. The following qualifying capacity (QC) methodology is adopted for valuation of all in-front-of-the-meter hybrid and co-located resources that are planning to access the Investment Tax Credit:

- Total QC = Effective ES QC + Effective Renewable QC
- *Effective ES QC* equals the minimum of:
  - (a) The energy (MWh) production from the renewable resource until 2 hours before the net load peak assuming charging is done at a rate less than or equal to the energy storage's capacity. This renewable charging energy is then divided by 4 hours to determine the QC; or
  - (b) The QC of the energy storage device.
- *Effective Renewable QC* equals the remaining renewable capacity, net of the capacity required to charge the battery (i.e., *Effective ES QC*), multiplied by the Effective Load Carrying Capability factor for the month.

12. A "hybrid resource" is defined as two or more resources (one of which is a storage project) located at a single point of interconnection with a single resource ID. "Co-located resources" are defined as two or more resources (one of which is a storage project) located at a single point of interconnection with two or more resource IDs.

13. Third-party demand response (DR) resources, procured by non-investor-owned utility 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 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.

14. The results of test dispatches required of third-party demand response (DR) resources shall be submitted as follows:

(a) The scheduling coordinator shall submit the 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 test results in their Load Impact Protocol analysis and reports submitted to the Commission.

15. The following clarifications to the Load Impact Protocol (LIP) process for third-party demand response (DR) resources are adopted:

(a) *Ex post* and *ex ante* load impacts are required at the sub-Load Aggregation Point level.

(b) Mid-year updates are permitted to reflect changes in customer enrollment if the change is reasonably large. In the compliance year, on a biannual basis, Energy Division shall update qualifying capacity (QC) values based on the actual customer enrollment volume associated with that resource in the California Independent System Operator's Demand Response Registration System. LIP results will be updated if QC values vary by more than 20 percent, or 10 MW, whichever is greater.

16. The Load Impact Protocol (LIP) reports and qualifying capacity values from a demand response provider's LIP results shall be posted publicly to the maximum extent allowable, while protecting customer privacy and market sensitive information of demand response providers by adhering to the Commission's existing confidentiality policies.

17. For a particular maximum cumulative capacity bucket, "availability" is defined as follows:

(a) Holding aside use limitations or outages, a resource is physically capable of dispatching the entire capacity designated in the given bucket in any and all hours associated with the minimum criteria for that bucket;

(b) Holding aside use limitations or outages, the resource will economically bid or self-schedule (in the California independent System Operator markets) the entire capacity designated in the given bucket in any and all hours associated with the minimum criteria for that bucket; and

(c) If the resource has use limitations, those limitations would not prevent bidding, self-scheduling, and dispatch during regular, specific hours associated with the minimum criteria for that bucket.

18. The revised maximum cumulative capacity (MCC) buckets are adopted as follows:

Category	Availability	Maximum Cumulative Capacity for Bucket and Buckets Above
DR	Varies by contract or tariff provisions, but must be available Monday – Friday, 4 consecutive hours between 4 PM and 9 PM, and at least 24 hours per month from May – September	8.3%
1	Monday – Friday, 4 consecutive hours between 4 PM and 9 PM, and at least 40 hours per month from May – September	16.0%
2	Every Monday – Friday, 8 consecutive hours that include 4 PM – 9 PM	22.2%
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)

All demand response (DR) allocations to load-serving entities (LSEs) through the Cost Allocation Mechanism and investor-owned utilities' DR allocations shall count towards an LSE's MCC bucket.

19. Shaped system penalties prices are adopted as follows: $8.88/kW-month in summer months (May through October) and $4.44/kW-month in non-summer months.

20. The provider of last resort (POLR) may be eligible for a limited system or flexible Resource Adequacy (RA) waiver for instances in which retail load is: (a) returned to the POLR with insufficient time to meet the RA requirement, or (b) not transferred from the POLR to another load-serving entity (LSE) as planned as a result of action or inaction by the LSE. The waiver shall be submitted through a Tier 2 Advice Letter.

21. A load-serving entity (LSE) shall have fulfilled their Resource Adequacy obligations in the six disaggregated "Pacific Gas and Electric Company (PG&E) Other" local capacity areas (LCAs) if the following requirements are met:

(a) The LSE makes the required demonstration as part of the current local waiver process through a Tier 2 Advice Letter for its disaggregated PG&E Other local capacity requirements; and

(b) The LSE, in its Year Ahead compliance filing, demonstrates procurement of local RA capacity within the PG&E Other LCAs such that the LSE's collective procurement in the six disaggregated PG&E Other LCAs meets the LSE's collective requirement for the disaggregated PG&E Other LCAs.

22. The effective flexible capacity (EFC) values for storage resources is modified as follows:

- If Psupplymin and Psupplymax = 0, then EFC = PmaxRA – PminRA.
- If Psupplymin and Psupplymax ≠ 0, then EFC = (PmaxRA - Psupplymin) – (PminRA - Pdemandmin).

For bi-directional storage, PmaxRA shall remain capped at Net Qualifying Capacity (NQC) and PminRA shall be capped at -NQC.

23. Rulemaking 19-11-009 remains open.

This order is effective today.

Dated ____________________, at San Francisco, California.