PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

FILED
05/22/18
09:56 AM

May 22, 2018

Agenda ID #16544
Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 17-09-020:

This is the proposed decision of Administrative Law Judges Peter Allen and 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 21, 2018, 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 8.3(c)(4)(B).

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

AES:lil

Attachment

Decision **PROPOSED DECISION OF ALJS ALLEN AND CHIV**
(Mailed 5/22/2018)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020

DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2019 AND REFINING THE RESOURCE ADEQUACY PROGRAM

Table of Contents

Title **Page**

DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2019 AND REFINING THE RESOURCE ADEQUACY PROGRAM

Summary

This decision adopts local capacity requirements for 2019 applicable to Commission-jurisdictional electric load-serving entities, and sets forth a process for adoption of flexible capacity requirements for 2019. Until new flexible compliance requirements for 2019 are adopted, the previously-adopted 2018 requirements remain in effect.

This decision also makes minor changes to the Resource Adequacy program, and provides policy and procedural guidance for future tracks of this proceeding.

This proceeding remains open.

1. Background

California Public Utilities Code Section 380(a)[1] states that: "The commission, in consultation with the Independent System Operator, shall establish resource adequacy (RA) requirements for all load-serving entities." Section 380(k) defines a "load serving entity" (LSE) as "an electrical corporation, electric service provider, or community choice aggregator." Accordingly, the Commission's RA program and its requirements apply to all LSEs under our jurisdiction. Certain small or multi-jurisdictional LSEs may be subject to different RA requirements.

Additional information on the procedural history of this proceeding is set forth in the Order Instituting Rulemaking for this proceeding. Prior Commission RA decisions (D.) 15-06-063, D.16-06-045 and D.17-06-027 provide additional detail on the procedural and substantive background of this proceeding.

A Scoping Memo for this proceeding was issued on January 18, 2018. 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

[1] All statutory references are to the California Public Utilities Code unless stated otherwise.

Scoping Memo established multiple tracks, with issues falling into Track 1, Track 2 and Track 3. In general, Track 1 issues are issues that need to be resolved early (such as adopting Local Capacity Requirements (LCR) and Flexible Capacity Requirements (FCR) for 2019), or issues that are capable of being resolved early. In addition, Track 1 can make preliminary findings or policy determinations to provide guidance on issues to be addressed in more detail in Track 2 or Track 3.

Track 1 proposals were filed and served by parties and the Commission's Energy Division on February 16, 2018. The parties submitting proposals were: the Alliance for Retail Energy Markets (AReM), the California Independent System Operator Corporation (CAISO), Calpine Corporation (Calpine), the California Wind Energy Association (CalWEA), the City of Lancaster, Marin Clean Energy, Silicon Valley Clean Energy Authority, Peninsula Clean Energy Authority, East Bay Community Energy and Sonoma Clean Power Authority (collectively the CCA Parties), the Center for Energy Efficiency and Renewable Technologies (CEERT), the California Energy Storage Alliance (CESA), Cogentrix Energy Power Management, LLC (Cogentrix), Diamond Generating Corporation (Diamond), the Independent Energy Producers Association (IEP), Los Angeles Community Choice Energy, Desert Community Energy and Western Riverside Council of Governments (collectively the Joint CCAs), CPower, Enernoc, Inc. and Energyhub (collectively the Joint DR Parties), Middle River Power, LLC (Middle River), NRG Energy, Inc. (NRG), the Office of Ratepayer Advocates (ORA), Pacific Gas and Electric Company (PG&E), Powerex Corporation (Powerex), San Diego Gas & Electric Company (SDG&E), the Sierra Club, Southern California Edison Company (SCE), Southwestern Power Group II, LLC (SWPG), Wellhead Electric Company, Inc. (Wellhead), and the Western Power Trading Forum (WPTF).

Workshops on the proposals were held on February 22 and 23, 2018, with comments on the workshop and proposals filed on March 7, 2018 and reply comments on March 16, 2018.

Comments were received from AReM, CAISO, Calpine, CalWEA, the CCA Parties, CEERT, CESA, the California Large Energy Consumers Association (CLECA), Cogentrix, Diamond, the Green Power Institute (GPI), IEP, the Joint CCAs, the Joint DR Parties, LS Power Development, LLC (LS Power), Middle River, NRG, ORA, PG&E, SDG&E, Shell Energy North America (US), LP (Shell), the Sierra Club and the California Environmental Justice Alliance (Sierra Club/CEJA), the cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (collectively the Six Cities), SCE, SWPG, the Utility Reform Network (TURN), Wellhead, and WPTF.

Reply comments were received from AReM, the Bay Area Municipal Transmission Group (BAMx), CAISO, Calpine, CalWEA, the CCA Parties, CEERT, CESA, CLECA, Cogentrix, IEP, the Joint CCAs, the Joint DR Parties, Middle River, NRG, ORA, PG&E, SCE, Sierra Club/CEJA, TURN, the Union of Concerned Scientists (UCS), Wellhead, and WPTF.

2. Issues Before the Commission

The Scoping Memo identified the following issues as being within the scope of Track 1:

1) Adopting the 2019 LCR;
2) Adopting the 2019 FCR;[2]
3) Adopting the 2019 System RA Requirements; and
4) Top Priority Modifications to the RA Program.

This last category includes a) resource adequacy and potential cost allocation issues that arise as a result of load migration; b) RA program reforms necessary to maintain reliability while reducing potentially costly backstop procurement; c) any necessary updates to Effective Load Carrying Capacity (ELCC) modeling methodology and results; d) Alignment of RA measurement hours with CAISO availability assessment

[2] Including possible revisions to the Commission's Flexible RA rules, depending on timing.

hours (AAH); and e) other time-sensitive issue identified by Energy Division or by parties in proposals. (Scoping Memo at 6-7.)

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

3. Discussion

3.1. 2019 LCR

The local RA program was first adopted in D.06-06-064. That decision adopted a framework for local RA and established local procurement obligations for 2007 only. A series of subsequent decisions (most recently D.17-06-027), established local procurement obligations for 2008 through 2018. The local RA program and associated regulatory requirements adopted in those decisions continue in effect until changed, subject to the 2019 LCRs and procurement obligations adopted by this decision.

The RA program includes both "system" and "local" RA requirements. Each LSE must procure sufficient RA capacity resources to meet both obligations. "System" RA requirements are discussed further below. "Local" RA requirements are calculated based on the CAISO's annual LCR studies, and are allocated to each individual Commission-jurisdictional LSE by the Commission. Each LSE must then procure sufficient RA capacity resources in each local area to meet their obligations.

D.06-06-064 determined that a study of LCR, performed by the CAISO, would form the basis for this Commission's local RA program. The CAISO conducts its LCR study annually, and this Commission resets local procurement obligations each year after a review of the CAISO's LCR recommendations. This year, the CAISO's draft LCR study was received on April 23, 2018, and parties filed comments on the draft LCR study on May 4, 2018.

In response to the CAISO's draft LCR study, two utilities – SDG&E and PG&E – identified issues with the CAISO's LCR methodology, and particularly its lack of transparency. As SDG&E summarizes the issue:

> Finally, SDG&E is concerned, more broadly, that it has been consistently unable to reproduce the CAISO's LCR results. This appears to be the result of reliance on myriad assumptions that cannot be determined using the guidelines contained in the CAISO LCR manual. […] Ensuring that LSEs have the ability to perform separate studies using known assumptions would enhance transparency and provide the Commission with additional useful data. (SDG&E May 4, 2018 Comments at 5.)

More specifically, SDG&E identifies issues with the CAISO's study methodology for the San Diego – Imperial Valley (SD-IV) local area. SDG&E questions the CAISO's choice to examine the SD-IV area in conjunction with the LA Basin areas, rather than separately, and the CAISO's conclusion constraining phase shifter flow to zero, preventing south-to-north flows of electricity. (*Id*. 2-4.) According to SDG&E, the CAISO's study does not provide adequate substantiation to allow either SDG&E or the Commission to properly evaluate the results of the study.

PG&E makes a similar point, using a different example:

- PG&E requests that the CAISO flag in its results when an approved operating procedure has been used to optimize the results of the most critical contingency. Operating procedures allow the system operator to take action to mitigate the impact of contingencies as they arise. The CAISO currently enforces validated and approved operating procedures in its LCR analysis but does not identify when (and which) particular operating procedures are actually enforced in the results.
- PG&E proposes that the CAISO results include a flag that identifies when an operating procedure associated with a contingency was enforced in the analysis. This would increase transparency within the results. (PG&E May 4, 2018 Comments at 3.)

The fact that sophisticated LSEs such as PG&E and SDG&E are requesting additional transparency, and are having difficulty reproducing the CAISO's LCR results is in fact a problem that needs to be addressed going forward.

The final LCR study for 2019 was received by the Commission on May 15, 2018. The CAISO states that the assumptions, processes and criteria used for the LCR study were discussed and recommended in a stakeholder meeting, and on balance mirror those used in the 2007 through 2018 LCR studies. The CAISO identified and studied capacity needs for the same ten local areas as in previous studies: Humboldt, North Coast/North Bay, Sierra, Greater Bay, Greater Fresno, Big Creek/Ventura, Los Angeles (LA) Basin, Stockton, Kern, and San Diego/Imperial Valley.

The CAISO states that total LCR needs increased by 37 megawatt (MW) or ~0.0% for 2019. For specific regions, needs decreased in Humboldt due to load forecast decrease, Bay Area due to new transmission projects, and San Diego due to downward trend for load combined with an increase due to loss of net qualifying capacity at the most effective location in mitigating the most limiting contingency. 2019 LCR needs increased in North Coast/North Bay, Stockton, Big Creek/Ventura, and LA Basin due to load forecast increase, Sierra due to load and resource distribution, and Kern due to change in limiting line section.

SDG&E criticizes the Final LCR Report for not remedying the problems that SDG&E identified in the Draft LCR Report, and states:

> Finally, SDG&E repeats the concern articulated in its comments on the Draft Report that CAISO's LCR results are a "black box" that lack necessary transparency. This appears to be the result of reliance on myriad assumptions that cannot be determined using the guidelines contained in the CAISO LCR manual. Ensuring that LSEs have the ability to perform separate studies using known and verifiable assumptions would enhance transparency and provide the Commission with the analytic data it requires to protect ratepayers. (SDG&E May 18, 2018 Comments at 4.)

PG&E similarly complains that, "As discussed below, the Final LCR Report does not address the comments PG&E provided on the Draft LCR Report." (PG&E May 18, 2018 Comments at 1.) PG&E then reiterates its substantive criticisms, including that the CAISO did not provide certain relevant and useful information. (*Id*. at 1-4.)

Oddly, the CAISO filed comments on its own Final LCR Report. The comments themselves, however, are not really comments on the Final LCR Report, but instead respond to SDG&E's May 4, 2018 criticisms of the CAISO's Draft LCR Report, and explain why the CAISO did not incorporate the changes requested by SDG&E. (CAISO May 18, 2018 Comments at 1-5.) By filing this information on May 18, rather than with its Final LCR Report on May 15, the CAISO prevented SDG&E from responding to the arguments it makes, and has hindered SDG&E and the other parties from making fully informed comments on the CAISO's Final LCR Report. We accordingly give the CAISO's May 18, 2018 comments no weight.

CAISO's recommended 2019 LCR values are summarized in the following table, with the 2018 LCR provided for comparison. With reservations and concerns, we adopt the CAISO's recommended values.

2019 Local Capacity Requirements			
	2019 LCR Need Based on Category C*** with Operating Procedure		
Local Area Name	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	165	0	165
North Coast/North Bay	689	0	689
Sierra	1964	283*	2247
Stockton	427	350*	777
Greater Bay	4461	0	4461
Greater Fresno	1670	1*	1671
Kern	472	6*	478
LA Basin	8116	0	8116
Big Creek/Ventura	2614	0	2614
San Diego/Imperial Valley	4026	0	4026
Total	24604	640	25244

* CAISO note: No local area is “overall deficient.” Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency, the numbers are carried forward into the total area needs. 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.

** CAISO note: Since “deficiency” cannot be mitigated by any available resource, the “Existing Capacity Needed” will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.

*** CAISO note: TPL 002 Category B is generally equivalent to TPL 001-4 Category P1. TPL 003 Category C is generally equivalent to TPL 001-4 P2 through P7. Current LCR study report is compliant with existing language in the ISO Tariff Section 40.3.1.1 Local Capacity Technical Study Criteria to be revised at a later date.

2018 Local Capacity Requirements			
	2018 LCR Need Based on Category C* with Operating Procedure**		
Local Area Name	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	169	0	169
North Coast /North Bay	634	0	634
Sierra	1826	287*	2113
Stockton	398	321*	719
Greater Bay	5160	0	5160
Greater Fresno	2081	0	2081
Kern	453	0	453
LA Basin	7525	0	7525
Big Creek/Ventura	2321	0	2321
San Diego/Imperial Valley	3833	199	4032
Total	24400	807	25207

* CAISO note: No local area is "overall deficient." Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency, the numbers are carried forward into the total area needs. 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.

** CAISO note: Since "deficiency" cannot be mitigated by any available resource, the "Existing Capacity Needed" will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.

*** CAISO note: TPL 002 Category B is generally equivalent to TPL 001-4 Category P1. TPL 003 Category C is generally equivalent to TPL 001-4 P2 through P7. Current LCR study report is compliant with existing language in the ISO Tariff Section 40.3.1.1 Local Capacity Technical Study Criteria to be revised at a later date.

3.2. 2019 FCR

D.13-06-024 and D.14-06-050 adopted a flexible capacity requirement to begin in 2015 and defined guidelines for its implementation, and D.15-06-063 adopted FCR for 2016. D.13-06-024 recognized a need for flexible capacity in the RA fleet and defined flexible capacity need:

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

> output, or reduce ramping needs, during the hours of "flexible need." (D.13-06-024 at 2.)

This year, the CAISO's final Flexible Capacity Needs Assessment for 2019 (FCR Report) was due on May 15, 2018. On that date the CAISO filed its Final Local Capacity Technical Analysis and its Final Availability Assessment Hours Technical Study for 2019, but stated:

> The CAISO is unable to provide the final 2019 Flexible Capacity Needs Assessment at this time due to recently received stakeholder comments identifying fundamental concerns with the CAISO's use of the hourly California Energy Commission (CEC) load forecast data in determining the flexible capacity requirements. As a result of these comments, the CAISO intends to recalculate the final 2019 Flexible Capacity Needs Assessment to develop minute-by-minute net-load forecasts using actual 2017 load data adjusted for 2019 monthly system peak load forecasts rather than the CEC-provided hourly load figures. … The CAISO will make its best efforts to file the Final Flexible Capacity Needs Assessment with the Commission by close of business on May 21, 2018. (California Independent System Operator Corporation 2019 Annual Resource Adequacy Related Analyses at 1.)

Because the CAISO is recalculating the final figures for 2019, and those figures will not be available in time to be incorporated into the proposed decision, we do not adopt new 2019 FCR figures in this decision. Accordingly, the adopted 2018 FCR figures remain in effect. For convenience, those figures are reiterated in the below table.

2018 Flexible Capacity Needs

NOTE: All numbers are in Megawatts	CAISO System Flexible Requirement	CPUC Flexible Requirement	CPUC		
			Category 1[3] (minimum)	Category 2 (100% less Cat. 1 & 3)	Category 3 (maximum)
January	13,415	12,437	4,806	7,010	622
February	14,409	13,151	5,081	7,413	658
March	13,435	12,801	4,946	7,215	640
April	12,272	11,876	4,589	6,694	594
May	13,095	12,308	6,746	4,946	615
June	11,497	10,688	5,858	4,295	534
July	10,908	10,156	5,567	4,081	508
August	11,219	10,789	5,914	4,336	539
September	14,248	13,468	7,383	5,413	673
October	14,271	13,291	5,135	7,491	665
November	14,505	13,569	5,243	7,648	678
December	15,743	14,611	5,646	8,236	731

When the CAISO files and serves its final FCR Report in this proceeding, parties will have until the end of the third business day after the date the CAISO served its FCR Report to file and serve responsive comments. The final FCR Report and party comments will provide the basis for a separate decision that may modify this decision by adopting new FCR figures for 2019.

3.2.1. Revisions to Flexible RA Capacity

Several parties submitted proposals for flexible capacity reforms. The CAISO submitted the current version of its Flexible Resource Adequacy Capacity Must Offer Obligation (FRAC MOO) proposal, which it claims will better align forward procurement

[3] The CAISO divides the FCR into categories 1 through 3, or base flexibility, peak flexibility, and super-peak flexibility, as described in CAISO tariff Sections 40.10.3.2 and 40.10.3.3.

with the CAISO's operational needs and how it commits and dispatches resources. The CAISO contends that the current flexible framework does not ensure adequate ramping capability to address uncertainty between the day-ahead and real-time markets. To fill this gap, it proposes to develop three products: a five-minute flexible resource, a 15-minute flexible resource, and a day-ahead shaping resource, but the proposal is not fully developed. The CAISO states that it submitted the proposal in Track 1 as an initial step to begin discussions, aiming for adoption of a final framework in Track 2. (CAISO Proposal at 6-7.)

Cogentrix and Wellhead submitted proposals for a "fast flexible" RA requirement. Resources that have fast start up, ramping and shut-down capability would be eligible. (Cogentrix Proposal at 4, Wellhead Proposal at 2-4.) Middle River, LS Power, IEP and Diamond support the idea of a fast flexible requirement, but with differences in how it would be implemented. (Middle River Comments at 6, LS Power Comments at 3, IEP Comments at 7-8, Diamond Comments at 3.)

Other parties, including SCE, PG&E, TURN, ORA, Calpine, and NRG, oppose adopting new flexible RA requirements in Track 1 on the grounds that it is premature.[4] According to TURN, "it would be inappropriate for the Commission to implement such an ad hoc policy change outside of a more thorough review of flexible capacity needs by the Commission and/or the CAISO in its ongoing FRACMOO2 stakeholder initiative." (TURN Comments at 5.) GPI, WPTF, and Diamond voice support for the FRAC MOO proposal.[5]

Based on the preliminary nature of the proposals received, and comments indicating that more time is needed, it would be premature to make changes to the flexible RA requirements in Track 1, particularly since the FRAC MOO proposal is not

[4] SCE Comments at 3, PG&E Comments at 9-10, TURN Comments at 4-5, ORA Comments at 15-16, Calpine Comments at 13-15, NRG Comments at 16-17.

[5] GPI Comments at 2, WPTF Comments at 11, Diamond Comments at 2.

yet ready for consideration. The Commission will consider changes to the flexible RA requirements in Track 2.

3.3. 2019 System Requirements

The Scoping Memo in this proceeding, under the heading "Adopting the 2019 System RA Requirements," stated:

> In past years, the CPUC has imposed a system requirement based on the California Energy Commission (CEC) 1-in-2 monthly load forecast, plus a 15% planning reserve margin. Absent any alternative proposals, this framework is expected to continue for the 2019 RA program year. (Scoping Memo at 6.)

There are, however, alternative proposals that have been presented in this proceeding. For example, the CAISO proposes that the Commission adopt more conservative monthly load forecasts during the shoulder months. According to the CAISO, shoulder month variability in demand above the 1-in-2 level results in a reduction in the availability of the planning reserve margin, particularly in May and June. (CAISO Proposal at 9-10.) Middle River Power makes a similar recommendation, asking whether a 1-in-2 standard in appropriate for all seasons. (Middle River Proposal at 6.) Powerex has similar criticisms of the method used to calculate System RA requirements, and proposes a number of possible modifications. (Powerex Proposal at 10-11.) Other parties also raised issues that relate to System RA requirements.

Given the limited record development on issues that relate to System RA requirements, and the preliminary nature of the proposals made to address those issues, it is not appropriate to make significant changes to the methodology for setting System RA requirements in Track 1. We will not make a change now to the current requirements methodology, but we will examine System RA issues further in later stages of this proceeding.

3.4. Load Migration

In order to comply with Public Utilities Code Section 380(f), the Commission established the RA program through a series of decisions that ultimately established

(1) an annual process whereby LSEs were required to submit load forecasts for the upcoming year that were used to calculate and allocate RA requirements equitably among LSEs, and (2) a year-ahead process whereby LSEs were required to demonstrate their procurement to meet their RA requirements. The Commission has emphasized the importance of obtaining accurate load forecasts of the "best estimates" of future customers and associated load so that LSEs are not unnecessarily "saddled with excess capacity, or in need of additional capacity, under market conditions where they would not be able to conduct reasonable and appropriate transactions to acquire or dispose of capacity as needed for load migration."[6]

3.4.1. Mandatory CCA Participation in the Year-Ahead Process

In recent years, the number of Community Choice Aggregators (CCAs) in California has increased dramatically. In areas where CCAs are launching or expanding, customers are automatically defaulted into the CCA's service, resulting in a significant volume of electric load shifting from investor-owned utilities to CCAs. Further, CCAs have launched or expanded at times of the year that do not necessarily correspond with the year-ahead RA process. Without CCAs' participation in the year-ahead process, it was assumed that the departing load would continue to be served by utilities, and associated RA requirements were therefore assigned to those utilities, who then had to procure for that load. For example, by the end of 2017, the Commission had approved 11 CCA implementation plans for launch or expansion in 2018, corresponding to over 3,100 MW, but none of this load migration was captured in the year-ahead RA process.

In this proceeding, the proposal of the Commission's Energy Division seeks to ensure that all LSEs participate in all aspects of the year-ahead RA process, including submitting load forecasts and annual year-ahead filings, if they seek to serve load in the

[6] D.09-06-028, at 32.

following calendar year.[7] Energy Division further recommends that in order for an LSE to expand its territory in the following calendar year, the LSE's year-ahead load forecast and revised load forecast must reflect that expansion. (Energy Division Proposal at 4.)

Given the potential impacts of load migration that is not reflected in load forecasts, it is imperative to foster as much certainty as possible around load migration timing and volume in the year-ahead process. We agree with Energy Division that participation in the year-ahead forecasting process by all LSEs who plan to serve load in the following year, including accurate forecasting of expanded territory or customer base, will ensure a more equitable allocation of the RA requirements, because the estimates of expected load will more closely match actual load in the following year. Therefore, the Commission adopts Energy Division's proposal. Requiring all LSEs to participate in all aspects of the year-ahead RA process for load they will serve in the following year will mitigate the cost-shifting issues that can result from misaligned timing of LSEs' formation or expansion and the year-ahead RA filing schedule.

This proposal is adopted to apply to the current one-year ahead RA structure. As multi-year RA requirements are implemented in the future, alternate measures should be evaluated.

3.4.2. Reallocation of "Collective Deficiency" Procurement Costs

The current CAISO tariff establishes that once the annual RA showings are provided, the CAISO evaluates the effectiveness of the RA resources that have been procured to assess compliance in local capacity areas. In instances where the CAISO deems there is a "collective deficiency," the CAISO has an option under the Capacity Procurement Mechanism (CPM) to procure additional local RA capacity. The costs of any additional capacity are allocated to the LSEs in the area where the deficiency occurs.[8]

---

[7] Current Trends in California's Resource Adequacy Program: Energy Division Working Draft Staff Proposal at 4 (Energy Division Proposal).

[8] *See* CAISO Tariff Sections 40.3.2 and 43.8.3.

Under the current process, the CAISO allocates the cost of backstop procurement to only those LSEs that exist at the time when the allocation is made. Thus, if a CCA comes into existence after the allocation period, that LSE does not receive any allocation of the "collective deficiency" costs for the entire backstop capacity period. In turn, utilities that have since lost load receive a disproportionately larger share of the collective deficiency costs, which is ultimately shouldered by bundled customers.

PG&E proposes that the Commission and the CAISO establish a mechanism for allocating annual collective deficiency CPM costs across all LSEs that accounts for intra-year migration, thereby more fairly distributing costs. (PG&E Proposal at 4-5.) SCE, ORA, and CLECA support the proposal. (SCE Comments at 6-7, ORA Comments at 19, CLECA Comments at 7-8.) The CCA Parties support exploring an adjustment to account for intra-year load migration. (CCA Parties Reply Comments at 14-15.)

The Commission acknowledges that in periods of rapid load migration, annual cost allocation that is not adjusted to account for intra-year load migration results in cost allocation that is not proportional to actual load. However, the RA program participation requirements adopted in this decision are expected to mitigate this risk. In the future, all newly forming or expanding LSEs must provide more notice of their intention to serve new load, and therefore the Commission anticipates that they will receive appropriate backstop cost allocations based on that expected load.

If this problem nevertheless persists, the CAISO – not the Commission – assesses and allocates the CPM charges and could more appropriately address this issue. Currently, an ongoing stakeholder initiative is considering changes to the CPM to address this issue, but the timing for a resolution is unclear. At this time, it appears both unnecessary and premature to introduce an interim mechanism for reallocation of costs among Commission-jurisdictional LSEs, particularly because no specific proposal has been raised. However, if this issue persists, and if the CAISO is unable to implement a cost reallocation mechanism in a reasonable timeframe, the Commission may explore a reallocation mechanism and would invite parties to offer proposals on this issue.

3.4.3. Monthly Local and Flexible Requirement Adjustment

Under the current RA framework, system requirements are adjusted monthly to capture monthly load migration, while local and flexible requirements are subject to one mid-year adjustment. This structure results in local and flexible requirements theoretically being less accurate in capturing the impact of load migration.

In light of increased load migration, PG&E proposes monthly adjustments of local and flexible RA requirements. (PG&E Proposal at 3.) The CCA Parties do not oppose monthly adjustments so long as it is not a requirement for all LSEs on an ongoing basis but only for those LSEs who are affected by load migration. (CCA Parties Reply Comments at 14-15.)

We recognize the value in monthly adjustments to local and flexible requirements. However, the current mid-year adjustments for local and flexible requirements, in addition to other RA process adjustments and oversight, already occupy significant Commission staff resources. Implementation of monthly local and flexible adjustments would be even more burdensome for staff resources.

Furthermore, the Commission anticipates that with the adopted proposal in Section 3.4.1 above, unexpected intra-year load migration will be greatly reduced. Requiring participation in the year-ahead load forecast process will improve the accuracy of allocation of local and flexible requirements in the year-ahead period, thereby minimizing the need for monthly adjustments. We therefore reject this proposal.

3.4.4. Resolution E-4907 Waiver Extension

The waiver process established by Resolution E-4907 was intended to be a transitional option for those CCAs that had not submitted implementation plans before the introduction of the resolution but intended to launch or expand in 2018. The waiver process permitted CCAs to file implementation plans by March 2018, three months after the introduction of the resolution, in order to launch or expand service in 2018.

The CCA Parties propose that the waiver process be extended to 2019 because otherwise a CCA that did not register by March 2018 would be unable to launch or expand until 2020. (CCA Parties Proposal at 3.) The Joint CCAs support this proposal. (Joint CCAs Comments at 6-7.)

The waiver process was intended as a temporary option to accommodate CCAs that desired to expand or launch in 2018 but were caught unaware by the resolution's introduction. The Commission believes that the continued use of the waiver process beyond 2018 undermines the annual RA process. We therefore reject this proposal.

3.4.5. Resolution E-4907 Waiver Option B Price

For those CCAs who sought to launch or expand in 2018 but who did not file implementation plans by December 2017, Resolution E-4907 established two waiver options from the resolution's general submission timeframe. Option A provides that a CCA and utility reach an agreement as to cost responsibility and RA commitments and submit that agreement to the Commission via a joint advice letter. Option B provides that where a CCA and utility fail to reach an agreement, the CCA will submit an advice letter stating as such and affirming it agrees to be bound by a future Commission decision regarding cost responsibility for intra-year load migration.

Several parties submitted proposals addressing how the Commission should determine cost responsibility under Waiver Option B. PG&E and SCE propose that the Option B price reflect the Power Charge Indifference Adjustment (PCIA)-adopted benchmark price of $58.26/kW-year, since this is an administratively established measure of indifference. (PG&E Proposal at 5, SCE Proposal at 10.) By contrast, the Joint CCAs propose the use of a market-based formula consistent with a prior decision, D.10-03-022, involving the reopening of Direct Access. This "proxy market price" would be based on the utilities' bilateral contracts which would be submitted to the Commission for calculation of a weighted average monthly price. (Joint CCA Proposal at 2-3.)

In comments, the Joint CCAs and SCE propose a similar hybrid approach where the Option B price would be a weighted average of the PCIA benchmark for long-term contracts and a market-based price for short-term contracts. (Joint CCA Comments at 4-5, SCE Comments at 5-6.) The CCA Parties propose to use an average of the utility's short-term RA contracts during the prior year to determine the cost assignment. (CCA Parties Comments at 9-10.)

In reply comments, PG&E did not oppose SCE and the Joint CCAs' blended benchmark so long as the cost allocation methodology (CAM) resources are excluded from the calculation and long- and short-term purchases are allocated proportionally based on remaining bundled customers. (PG&E Reply Comments at 8-9.) ORA supported SCE and the Joint CCAs' proposed formula. (ORA Reply Comments at 3-4.) The CCA Parties continue to support use of a utility's average short-term RA contracts, or alternatively, the short-term RA values calculated by the utilities in Application (A.) 16-11-005 (Tree-Mortality Non-Bypassable Charge proceeding). (CCA Parties Reply Comments at 13-14.)

Given that RA costs for a particular year are based on a combination of RA procured in long-term and short-term contracts in the year-ahead timeframe, we find the blended approach proposed by SCE and the Joint CCAs to be reasonable. While the Commission finds the blended proposal for determining cost allocation to be reasonable, we note that of the CCAs that are utilizing the waiver option to date, none have chosen to exercise Option B. Since such waivers are only available for 2018, as discussed in Section 3.4.4, defining the cost allocation formula for Option B is moot and therefore the Commission does not adopt this proposal.

3.4.6. Clarification of Resolution's Waiver Negotiation Scope

The CCA Parties propose that the Commission reiterate that during the waiver negotiation process established by Resolution E-4907, a utility's proposal to a CCA be limited to "RA requirements and cost responsibility concerns raised by intra-year load migration," as stated in the resolution, and that additional requirements or conditions for cost transfers to protect against anti-competitive impacts will not be raised. (CCA Parties Proposal at 5.) The Joint CCAs support this proposal. (Joint CCAs Comments at 3.)

The Commission believes that it is unnecessary to adopt this proposal as the waiver process is not extended beyond 2018.

3.4.7. Options to Reduce RA Obligations for Departing Load

The CCA Parties propose that the Resolution's assertion that "the IOUs [investor-owned utilities] have fully procured all of the RA needs for load that may subsequently depart" be quantified and verified in this proceeding. (CCA Parties Proposal at 6.) The CCA Parties also state that mitigation measures should be considered, such as better forecasting of departing load, more frequent true-ups of RA responsibility, and revisiting RA procurement and solicitation practices by the utilities. (*Id.*) No parties commented on this proposal.

When CCAs do not participate in the year-ahead RA process or do not accurately represent phase-ins or expansions in their load forecast, that load is necessarily assigned to the utilities who are required to procure for it. This decision should reduce the uncertainty that surrounds load procurement. This proposal fails to provide specific details and is also duplicative of other proposals addressed elsewhere in this decision. We therefore decline to address or adopt them here.

3.4.8. Creation of a Memorandum Account

The CCA Parties propose that the Commission establish memorandum accounts for the utilities to track short-term RA costs associated with CCA load migration. (CCA Parties Proposal at 4.) No parties commented on this proposal, and the Commission does not find adequate support for this proposal. In future years, the year-ahead RA participation requirements adopted in this decision will minimize intra-year load migration costs. We therefore reject this proposal.

3.5. Multiple Year Ahead Procurement and Central Buyer

In the previous RA proceeding, the Commission declined to adopt a multi-year RA requirement; the Scoping Memo in that proceeding indicated that a durable FCR program should be adopted first, and the Commission had not done so. (D.17-06-027 at 17-18.) The Commission did, however, leave open the possibility that in the future a multi-year RA requirement could be implemented independently of a durable FCR program. (*Id.*) The OIR and Scoping Memo in this proceeding do not require the adoption of a durable FCR program prior to considering adoption of a multi-year RA requirement.

The Scoping Memo did, however, highlight recent procurement challenges, including the backstop procurement of three generating facilities (Metcalf, Yuba City and Feather River) through the CAISO's Reliability Must Run (RMR) tariff provisions, and two generating facilities (Moss Landing and Encina) through the CAISO's CPM. To address these and other issues, the Scoping Memo specifically noted that, "[p]otential approaches to reduce further out-of-market RA procurement, such as multi-year Local RA program and/or one or more central buyers (e.g., the large investor-owned utilities), will be prioritized for consideration in Track 1 of this proceeding" and that "[t]he Commission may also consider other ways to address this issue, such as increasing transparency… regarding which resources are essential for local and sub-area reliability." (Scoping Memo at 4.)

Accordingly, Energy Division and multiple parties, including ORA, PG&E, AReM, NRG, WPTF, Middle River, IEP, and Diamond, proposed multi-year RA programs.[9] Noting lower levels of forward contracting than in previous years, and backstop procurement and procurement deficiencies, the Commission's Energy Division proposed a multi-year framework for local resource adequacy. Energy Division's proposal would extend three to five years (with varying procurement percentages), with either a central buyer or allocation of multi-year sub-local requirements to each LSE.[10] While there was general consensus in support of a further study or studies on multi-year procurement needs, there was less consensus on the focus of the studies and who should perform them. The issue of what studies should be undertaken is discussed further below.

[9] *See*, e.g. AReM Proposal at 5-6, PG&E Comments at 5, NRG Proposal at 4, ORA Comments at 9-10, WPTF Proposal at 3-5, Middle River Power Proposal at 5-6, IEP Proposal 4-7.

[10] *Current Trends in California's Resource Adequacy Program: Energy Division Working Draft Staff Proposal* at 52-59. (Energy Division Proposal)

Other parties also focus on multi-year local resource adequacy requirements, either for all local RA or for only those resources that are needed for reliability. ORA proposes that an LSE or coalition of LSEs centrally procure resources that are identified as essential for reliability. AReM proposes a three year forward local RA obligation that would decline each year, to 70% in year 2 and 30% in year 3. (AReM Proposal at 5-6.) PG&E proposes a multi-year RA framework for local capacity needed one to five years forward, with a central procurement agent, with costs recovered through a non-bypassable transmission charge paid by all customers of the relevant Participating Transmission Owner (PTO). (PG&E Proposal at 7-8.)

Other parties focus on multi-year procurement for system and flexible requirements, in addition to local requirements. SDG&E proposes that the CAISO assess all resources necessary for system, local and flexible reliability over a five-year horizon, and that a central agent procure the incremental resources necessary to meet the identified reliability needs, with costs to be recovered through the transmission access charge- (SDG&E Proposal at 4-6.) WPTF proposes that the Commission adopt three to five year requirements for flexible, system and local and that the CAISO administer a forward RA auction to facilitate this procurement. WPTF asserts that the auction should encourage new generation and therefore diminish the need for procurement of new resources through the long-term procurement plan (LTPP) process and that this framework would allow LSEs the option to self-supply or rely on a CAISO auction. (WPTF Proposal at 3-5.) Middle River proposes a three to five year forward procurement framework that includes flexible, local and system requirements and a central buyer. (Middle River Proposal at 5-6.) IEP proposes a straight line 5% declining forward requirement for year two (95% local, 85% flexible) and year three (90% local, 80% flexible). (IEP Proposal at 6-7.) Diamond proposes the development of a multi-year procurement framework for flexible and local. Diamond argues that "[t]oday's approach to RA procurement is too ad hoc for resource owners to prudently plan for future upgrade and maintenance decisions when they are nearing the end of their current commercial contract." (Diamond Proposal at 3.) They offer three key elements which will address the risk of economic retirement in a future framework, including "a specific procurement process for existing, firm capacity resources; solicitation opportunities for specific operating characteristics; and, a three-year procurement cycle for contracts with five-year terms." (*Id.* at 1-2.)

Rather than a specific proposal, SCE proposes a longer process (18 months) and six key principles that should underlie a future framework. These principles include: ensuring RA changes are aimed at helping California meet its carbon reduction goals, ensuring RA obligations are equitable amongst LSEs, potential use of a central procurement agent to ensure equitable cost allocation, coordinating with the Integrated Resource Planning (IRP) process to help identify alternatives to the existing fossil fuel fleet, coordinating with the CAISO to ensure reliability and mitigate backstop procurement, and having a transition plan to get from the current state to the desired end state. (SCE Proposal at 3-5.)

NRG proposes a multi-year forward framework built upon three principles: an enforceable three-year minimum system and local requirement, a requirement that procurement percentages be "sufficiently high as to ensure that resources that will be needed in the 'out' years are under contract," and a mechanism to account for changes in load. (NRG Proposal at 3-4.)

Some parties expressed concern about the implementation of a multi-year RA requirement, and suggested that more information was needed first, or that certain conditions should be applied, but there was no significant opposition to the general concept.

While acknowledging these concerns, the Commission believes that there is value to having a multi-year local RA requirement to ensure that resources needed for reliability are procured in an orderly fashion, and intends to implement a multi-year local RA requirement in Track 2 of this proceeding. Although it is premature to spell out the details of such a requirement at this point in the proceeding, we can lay the groundwork to support implementation of a multi-year local RA requirement for 2020. We do not intend to adopt multi-year requirements for flexible and system RA in this proceeding, particularly in light of anticipated changes to the flexible RA construct. In the future, the Commission may consider an expansion of multi-year requirements to flexible and/or system RA.

3.5.1. Duration of Multi-Year RA Program

The Commission's Energy Division proposed a three to five-year forward local requirement (Energy Division Proposal at 53). While IEP supported a five-year duration (IEP Reply Comments at 4), other parties, such as AReM, TURN and the CCA Parties,[11] preferred a three-year duration. No party is proposing a duration longer than five years. Accordingly, in their Track 2 testimony parties should propose a multi-year local RA requirement with a three-to-five-year duration, which would be implemented beginning with the 2020 RA program year

3.5.2. Amount of Forward Local RA Procurement

Energy Division and several parties propose specific percentages for multi-year local resource adequacy procurement. Energy Division proposes a 100% requirement for Year 2 and 80% for Year 3 (possibly extending through Year 5). AReM proposes 70% for Year 2 and 30% for Year 3, IEP proposes 95% in Year 2 for local (declining 5% per year thereafter), and the CCA Parties propose 90% for Year 1 (rather than the current 100%) and a 25% for Years 2 and 3.[12]

As documented in the recent multi-year contracting analysis, as of April 2017, LSEs had procured 150% of aggregate 2017 local requirements, as well as 99% of aggregate 2018 requirements and 81% of aggregate 2019 requirements. Nevertheless, this level of procurement was not sufficient to maintain the necessary sub-local needs, as highlighted by the recent RMR and CPM designations.

---

[11] *See*, AReM Reply Comments at 3-4, TURN Comments at 2-3, CCA Parties Comments at 6.

[12] AReM Proposal at 6, IEP Proposal at 6-7, CCA Parties Comments at 6.

In light of the need to increase market certainty in the near term, we find that a 100% local requirement for the first two years is appropriate. In their Track 2 testimony, parties should include proposals with 100% forward local RA procurement for the first two years.

Parties should propose a reasonable amount of local RA procurement for Year 3 (and beyond, if a longer program is proposed) basing their proposals on data such as that presented by Energy Division in its proposal. In general, local RA procurement requirements should be greater than current voluntary local RA forward procurement levels. This is necessary to achieve the goal of increased market certainty.

3.5.3. Central Buyer

Energy Division presented two approaches to a local multi-year RA requirement, one with the utilities acting as a central buyer, and one with the LSEs responsible for meeting their own local and sub-local RA requirements. (Energy Division Proposal at 52-59.) Energy Division's proposal identified a number of advantages and disadvantages for each approach, but did not recommend a particular approach. (*Id.*)

According to Energy Division's proposal, some of the advantages of the central buyer approach include: more efficient procurement, with one entity buying the local and sub-local resources necessary to ensure reliability; reduction in stranded costs (currently, if entities procure local resources and then lose load, this procurement could be stranded if they are unable to sell the resource to other entities); and procurement of the "right" resources, rather than potentially less effective local resources, with the potential for backstop procurement for sub-area deficiencies identified by the CAISO (as occurred in 2017 for the 2018 compliance year). In addition, having a central entity could help to address market power in locally constrained areas and potentially help to ensure the least cost solution for all customers (bundled and unbundled). Finally, a central buyer could ensure local reliability procurement is coordinated with least-cost best-fit principals, preferred resource mandates, and Senate Bill 350 policy goals. (*Id.* at 57-59.)

On the other hand, if local procurement responsibility remains with individual LSEs rather than with a central buyer, the primary benefit would be that the individual LSEs maintain their procurement autonomy, and backstop procurement could potentially be reduced if local areas are disaggregated to the sub-area level. (*Id*.)

Parties raised a variety of concerns with both the central buyer approach and the LSE-procurement approach. Some parties suggested that the CAISO should act as a central buyer for multi-year RA. (*See*, e.g. WPTF Comments at 5-6, AReM Comments at 4.) Other parties argue against the CAISO acting as the central buyer. TURN and ORA both raise concerns with the CAISO being the central procurement agent because of potential for conflicts between California's environmental goals and federal regulations. TURN suggests that "[b]y engaging the utilities as central buyers, the state of California will be able to pursue its environmental policies with much less chance of intervention by the Federal Energy Regulatory Commission (FERC) or federal courts." (TURN Comments at 3, ORA Comments at 6-7).

A few parties argue that the investor-owned utilities are not in the best position to be the central buyer since they will be serving fewer customers in the future as their loads depart to CCAs (WPTF Comments at 5, SDG&E Comments at 6, AReM Comments at 5). Other parties suggest that the utilities are insufficiently independent to act as a central agent, given that they compete with other LSEs for retail load and invest in alternatives, such as storage and transmission, that could obviate the need for some RA resources (Calpine Comments at 2-3, AReM Comments at 5).

Parties also raise concerns with the LSE-procurement approach. SCE argues that without a central buyer, a multi-year RA framework will not work because load migration and stranded cost issues need to be resolved first (SCE Reply Comments at 2). NRG argues that "the idea of allocating LSE-specific, increasingly granular procurement targets, which are to be satisfied through purely bilateral procurement, seems destined to fail" (NRG Comments at 7).

Another potential concern that was identified with the LSE-specific approach was that market participants may not have the ability to efficiently and cost effectively transact for small amounts of capacity. According to the CAISO, in the "longer-term, continued disaggregation of load serving responsibilities and load migration will require a more coordinated approach" (CAISO Comments at 8).

Weighing both the concerns and the potential benefits of moving to a central buyer system, we believe that a central buyer system - for at least some portion of local RA - is the solution most likely to provide cost efficiency, market certainty, reliability, administrative efficiency, and customer protection. At the same time, to preserve procurement flexibility for all LSEs and limit program modifications to only the most critical areas, we do not adopt a framework for central procurement of system or flexible RA at this time. Central procurement of system or flexible RA may be considered in future years.

Therefore, parties should propose central buyer structures for multi-year forward procurement of local RA in their Track 2 testimony. Proposals involving centralized procurement may have a single central buyer or a single central buyer per Transmission Access Charge (TAC) area. It is possible that there could be more than one central buyer per TAC area, and we are willing to consider such proposals, but we are not yet persuaded of the feasibility of permitting two buyers per TAC area. Therefore, any such proposals must provide additional detail to allow the Commission to evaluate their feasibility. Specifically, proposals with two buyers in one TAC area must be concrete and implementable, and: 1) address equitable allocation of costs to all customers, and 2) ensure cost-effective, efficient and coordinated procurement for each local and sub-local area within the TAC.

Finally, all proposals must address how the central buyer structure would balance economic procurement criteria with other essential state policies, such as greenhouse gas emissions reductions targets and consideration of impacts on disadvantaged communities.

In particular, we remain concerned that a centralized capacity market may not meet these objectives.

3.5.4. Studies

While there was general consensus in support of a further study or studies on multi-year procurement needs, there was less consensus on the focus of the studies and who should perform them. We acknowledge the importance of further study in not only setting procurement requirements, but also in guiding multi-year procurement so as to optimally select the right resources needed today and into the future to ensure grid reliability. At the same time, we currently have sufficient information and studies to move forward with the initial implementation of a multi-year local RA procurement and a central buyer system. Given the need to move quickly to maintain the integrity of the RA program under changing market conditions, we will begin with continued reliance on existing studies, while simultaneously moving forward with new ones.

The existing Local Capacity Requirement Technical Studies will be a primary input to the Commission's determination of multi-year local needs. However, if we adopt a three or four-year local RA program in Track 2, it may be helpful if the CAISO were to add a study that matches this new timeframe, and not just the current one and five year studies.

We also note that the CAISO, through its existing Transmission Planning Process (TPP), is currently considering transmission alternatives to reduce LCR.[13] Any identified alternatives through the TPP should be coordinated with future procurement of local RA.

In addition to a study that is used in setting requirements, we also see the need to study the characteristics of the current resource fleet and potentially identify quantitative or qualitative criteria that consider additional local resource attributes (such as flexibility, locational effectiveness, efficiency, emissions and impacts on disadvantaged

[13] http://www.caiso.com/Documents/Presentation-LocalCapacityRequirementReductionStudy.pdf.

communities). Energy Division may propose such a study in Track 2, where it can be considered in more detail and coordinated with any IRP planning necessary to meet the state's 2030 greenhouse gas reduction goals.

As far as a study that seeks to identify needed resources that are falling off of RA contracts, sometimes referred to as a risk of retirement study, the Commission is not persuaded that this type of study is a feasible solution to a growing problem. In order to take into consideration, the state's broader policy goals, a more holistic approach to local procurement planning is necessary to identify the resources that will be needed in the future.

3.6. Short Term Solutions for 2019

On February 28, 2018, NRG submitted letters to the Commission and the CAISO indicating that it intended to retire Ormond Beach, a 1,500 MW facility, as of October 1, 2018, and Ellwood, a 54 MW facility, as of January 1, 2019. The CAISO's Final LCR Study identifies a local capacity need to retain the Ellwood Generating Station (Ellwood) and one of the generating units at Ormond Beach (Ormond Beach), and states that "[T]he CAISO intends to seek a reliability-must run (RMR) designation for Ellwood and one of the Ormond Beach units at the CAISO's July Board of Governors meeting." (California Independent System Operator Corporation 2019 Annual Resource Adequacy Related Analyses at 1-2.)

One of the primary purposes of Track 1 consideration of a multi-year local procurement framework was to reduce or eliminate the need for backstop procurement. Accordingly, in an attempt to address the potential backstop procurement of these resources for 2019 and 2020, we direct SCE to negotiate, if possible, contracts for these facilities, which are required to ensure the reliability of the grid, the costs of which would then be allocated similar to other CAM resources procured for local reliability. Should these negotiations prove successful, SCE should file a Tier 2 Advice Letter seeking approval of these contracts. We expect SCE would work with the CAISO to ensure that these facilities are indeed needed and consider the duration of this need, SCE should enter into contracts only if doing so is expected to be less costly than any applicable backstop procurement measures.

We recognize that some parties have expressed concern about "on behalf of" procurement, but we note that absent the type of contract authorized herein, these facilities are likely to be procured through the CAISO's backstop procurement mechanisms, which would then be allocated to all customers in SCE's TAC area. In addition, we note that other parties have expressed concerns about contracts with fossil-fired resources located in disadvantaged communities, but we also note that these facilities are scheduled to retire, and that this procurement is merely a bridge to ensure reliable operation of the grid while more durable solutions are being considered.

Likewise, should any additional resources provide retirement notices, and should CAISO find that these resources are needed to meet local reliability needs for 2019, we hereby direct the Utilities to seek contracts to obviate the need for the backstop procurement on behalf of all customers its service area as an interim measure while more durable measures are developed.

A number of parties proposed other interim measures for 2019, including disaggregation of local requirements (PG&E Comments at 7), electronic bulletin boards communicating sub-area local targets to LSEs and revising CAISO's CPM tariff (CCA Parties Comments at 8), and adopting multi-year procurement for the 2019 RA program year. (CAISO Comments at 8, Calpine Comments at 1, IEP Proposal at 1-2. We do not adopt these proposals at this time. Based on the record before us, it is not clear that they would be effective in addressing the immediate issues confronting the Commission in this proceeding.

3.7. ELCC

The Commission adopted an Effective Load Carrying Capacity (ELCC)[14] methodology in D.17-06-027. In doing so, however, the Commission adopted ELCC values designed to "ease the transition" to ELCC by backing out the effects of behind-the-meter photovoltaic (PV) generation on the solar ELCC value. (D.17-06-027 at 20.) While the adoption of ELCC significantly reduced the overall capacity values for solar generation compared to the prior methodology, this adjustment to behind-the-meter PV partially offset that reduction.

A number of parties propose to include behind-the-meter PV in the Commission's ELCC modeling. Calpine argued that it "is irresponsible to continue to ignore the impact of behind-the-meter PV on ELCC". (Calpine Proposal at 5-6.) Calpine and WPTF propose that if behind-the-meter PV continues to be treated as supply, adopted estimates need to include its impact, or if it is not modeled as supply, that the modeling should use load profiles that reflect the impact of behind-the-meter PV. (Calpine Proposal at 5-6, WPTF Proposal at 6-7)

According to SCE, behind-the-meter solar is a significant contributor to California's solar generation portfolio. It impacts RA by shifting the net load peak, and the current approach results in ELCC values being biased upwards. SCE proposed that the Commission review the proposals from Energy Division and Calpine that were originally presented in Rulemaking (R.) 14-10-010, and adopt one of them to address "the disparate treatment of solar resources in demonstrating resource adequacy." (SCE Proposal at 5-6.) Middle River proposed that the Commission ensure that the ELCC methodology for behind-the-meter solar does not artificially depress the need for procuring RA capacity. (Middle River Proposal at 7.)

In their comments, LS Power, Middle River, Cogentrix, GPI, SWPG, PG&E, CalWEA, NRG and IEP support modeling behind-the-meter PV as supply side; ORA

[14] Also commonly referred to as Effective Load Carrying *Capability*.

recommends that the Commission direct parties to address the potential advantages and disadvantages of different methodologies for integrating behind-the-meter PV in Track 2 testimony and working groups before adopting a specific approach. (ORA Comments at 13.)

The CAISO believes that three viable options for treatment of behind-the-meter PV have been put forward: the Energy Division and Calpine proposals in R.14-10-010, the PG&E proposal to treat behind-the-meter PV as supply side, and the option of adjusting load requirements. The CAISO has no strong preference between the options as long as behind-the-meter PV is explicitly considered in the RA framework. (CAISO Comments at 6.)

While some parties support making changes to the ELCC values in Track 1 (*see*, e.g. NRG Reply Comments at 5, Calpine Comments at 5), multiple other parties support workshops or working groups in Track 2 to more carefully consider incorporation of behind-the-meter PV and its ramifications. (*See*, e.g. TURN Comments at 5-6, SDG&E Comments at 6-7, ORA Comments at 3.)

The solar ELCC values adopted in 2017 were transitional. Moving to a more complete and accurate implementation of ELCC requires that behind-the-meter PV be incorporated into the ELCC modeling framework. But before deciding whether to model behind-the-meter PV as supply side or incorporate its impact into load shapes, it is necessary to better understand the effects of this choice on resulting ELCC values. Accordingly, Energy Division should consider conducting studies to examine the implications of modeling choices on ELCC values, and may submit a proposal for integration of behind-the-meter PV into the ELCC framework later in this proceeding. Energy Division may hold workshops or convene a working group to discuss implementation details.

In addition to behind-the-meter PV values, parties raised other ELCC issues, including recommendations that the Commission evaluate wind and solar over multiple locations, and also evaluate variations in technology, such as concentrated solar, solar thermal and tracking PV. (*See*, e.g. ORA Comments at 10, CESA Reply Comments at 2, Sierra Club/CEJA Reply Comments at 4, IEP Comments at 9, SWPG Proposal at 5, PG&E Comments at 12.) SCE proposed that the Commission use a marginal rather than average ELCC value, and that a resource retain its RA value for the life of the resource. (SCE Proposal at 6-8.) Calpine, CalWEA, SWPG, IEP and CAISO support consideration of marginal values while SDG&E, PG&E and NRG oppose their use. (Calpine Comments at 13, CalWEA Comments at 2-3, SWPG Comments at 2, IEP Comments at 9, CAISO Comments at 9; SDG&E Comments at 7-10, PG&E Comments at 12-13, NRG Comments at 12-14.) CLECA supports consideration of the SCE proposal in Track 2. (CLECA Comments at 10.)

Similar to the approach we are adopting for consideration of behind-the-meter PV, these issues raise potentially complex consequences, and accordingly Energy Division should conduct more granular ELCC studies in order to understand the potential benefits of adopting locational or technological values and marginal values. Energy Division may hold workshops or convene a working group to discuss implementation details.

Calpine and Middle River proposed changes to the planning reserve margin (PRM), based on results from draft ELCC modeling runs conducted in the previous RA proceeding. (Calpine Proposal at 1-5, Middle River Proposal at 6.) While we do not adopt this proposal at this time, parties may raise or explore this issue further in Track 2 or Track 3 of this proceeding.

3.8. Alignment of Hours

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

Likewise, the Commission identifies RA "measurement hours" to establish Qualifying Capacity (QC) values for select resources, particularly non-dispatchable and demand response resources. The current RA measurement hours were adopted in D.10-06-036, the last RA proceeding in which the measurement hours were addressed. That decision adopted a QC methodology manual that codified QC calculation methods and adopted measurement hours for calculating QC of non-dispatchable and demand response resources. Since 2012, QC calculations for demand response (DR) and non-dispatchable resources[15] have been based on production or load drop during the following hours:

Month	Hours
November – March	HE17 – HE21 (4:00 p.m. – 9:00 p.m.)
April – October	HE14 – HE18 (1:00 p.m. – 6:00 p.m.)

Through 2017, the CAISO's AAH also corresponded with the above hours. Since the adoption of these hours, however, the grid has changed significantly with the rapid growth of solar production. With the proliferation of behind-the-meter solar PV, peak load hours on the grid have shifted later in the day, especially during summer months. In 2017, the CAISO conducted an analysis of peak load hours that led to a revision of its summer AAHs to 4:00 p.m. – 9:00 p.m. (in alignment with its winter assessment hours). Beginning in 2018, the CAISO is now using HE17 – HE21 as the AAHs for the duration of the year. The CAISO has announced plans to conduct a similar analysis annually in conjunction with its Flexible Capacity Requirements study.

The CAISO's adoption revised AAHs has led to a discrepancy between the hours used by the Commission to evaluate resource capacity and the hours when resources are required to offer capacity into the CAISO markets. This misalignment has not only led to

[15] *See* Commission's 2018 Qualifying Capacity Methodology Manual, at 13-18.

confusion and uncertainty among resource owners, but has the potential to affect grid reliability during high demand conditions.

Of the parties who addressed this issue, there was unanimous support to bring the Commission and the CAISO hours into alignment. Two proposals were raised as to how to best resolve this. Energy Division proposed that the CAISO submit the results of its annual AAH analysis into the RA proceeding for party comment and consideration by the Commission. The Commission would then adopt measurement hours to be used for QC value calculation of non-dispatchable resources for the following year. (Energy Division Proposal on RA Measurement Hours at 1.) By contrast, PG&E and the CAISO proposed that the Commission hours be set by reference to the CAISO AAHs. (PG&E Proposal at 6, CAISO Proposal at 4.)

The Joint DR Parties, ORA, WPTF, NRG, and CLECA submitted comments supporting Energy Division's proposal.[16] Middle River, PG&E, and CalWEA supported the proposal adopting the CAISO AAHs by reference.[17] In its reply comments, the CAISO supported adoption of either its proposal or Energy Division's proposal. (CAISO Reply Comments at 11.) Many parties supported aligning the hours but did not reference a specific proposal.[18]

Several parties commented that it was appropriate to have the Commission determine whether to adopt revised RA measurement hours, rather than have them set by reference to the CAISO AAHs, to allow an opportunity for parties to comment on any revision. The Commission agrees with this approach, as outlined by Energy Division's proposal, in an effort to preserve due process.

---

[16] Joint DR Parties Comments at 3, ORA Comments at 19, WPTF Comments at 6-7, NRG Comments at 10, CLECA Comments at 10.

[17] Middle River Comments at 7, PG&E Comments at 14-15, CalWEA Comments at 3-4.

[18] SCE Proposal at 9, NRG Proposal at 5, WPTF Proposal at 7, IEP Comments at 6, LS Power Comments at 4, SDG&E Comments at 12, Joint DR Parties Proposal at 5.

As an additional matter, ideally, the measurement hours for all resources would be implemented simultaneously. However, this is difficult for DR because load impact protocol (LIP) assessments are submitted to the Commission in April, whereas the RA decision is adopted in June. Therefore, measurement hours adopted in June will be incorporated in the load impact studies the upcoming fall, which will be submitted to the Commission in April for valuation of the following year's DR resources.[19] In comments, SDG&E proposed that the Commission require CAISO to establish AAHs for the following year by January 10 of each year so that the hours can be applied in the LIP analysis submitted in April. (SDG&E Comments at 12-14.) This proposal was supported by NRG. (NRG Reply Comments at 4.)

The Commission finds it unlikely that AAHs can be implemented successfully by January 10 under SDG&E's proposal given that it is only ten days from year end. Considering the time required to conduct analysis and finalize data for the CAISO's AAH analysis, this is not a reasonable timeline. Energy Division's proposal contemplates a lag in implementation for demand resources where the LIP analysis will use the most recently adopted measurement hours. Therefore, the Commission adopts the proposal outlined by Energy Division.

Upon consideration of the CAISO's annual analysis of the AAHs, filed on May 15, 2018, the Commission adopts the modification of the RA measurement hours to HE17 – HE21 (4:00 p.m. – 9:00 p.m.) for each month of the year beginning in 2019. This modification brings the Commission's measurement hours into alignment with the CAISO's AAH as of 2019.

---

[19] For example, the CAISO's AAH analysis submitted to the Commission in 2018 would be evaluated for use in 2019 QC calculations for all resources except DR. If adopted, the CAISO's hours would be implemented for calculation of DR QC values in 2020.

3.9. Other Issues

In D.14-06-050, the Commission held that: "[S]torage and DR may not be jointly aggregated to create a combined Storage-DR resource at this time, but we may explore this possibility in future compliance years." (D.14-06-050 at B-4.) CESA notes that this prohibition excludes projects which are currently being developed, and that there is no good policy basis for their exclusion. CESA accordingly argues that this prohibition be removed, so that combined storage and DR resources can be eligible for system (or local) RA, as long as they meet all other applicable criteria and conditions. (CESA Comments at 4.) Other parties agree with CESA. (*See*, Sierra Club Reply Comments at 4.)

We will remove the prohibition on combined storage and DR resources being eligible for RA. Going forward in this proceeding, parties should consider combined storage and DR resources to be eligible for system, local and flexible RA.

Sierra Club argues for greater transparency, and specifically that more information related to RA contracting should be made public, as contracting decisions (and resulting generation) can have an effect on the health of adjacent communities, including disadvantaged communities. (Sierra Club Proposal at 2.) ORA and UCS support Sierra Club's proposal, while Calpine opposes it as unworkable, inconsistent with other Commission decisions, and potentially inaccurate. (ORA Comments at 22, UCS Reply Comments at 1-2, Calpine Reply Comments at 6-8.)

We note that the Commission has addressed issues of confidentiality and disclosure of contracts in other proceedings in some detail, and that some of the contract information Sierra Club wants disclosed already is public; other information is not public, however, and may legitimately be confidential market-sensitive information that should not be publicly disclosed. The Commission does, however, support transparency, and is willing to consider proposals to increase transparency. Given the complexity of this issue and the relatively thin record currently before the Commission, it is more appropriate to address Sierra Club's proposal in Track 2.

A separate transparency-related suggestion was made by IEP, which recommended that the Commission consider (in Track 2) an electronic bulletin board or centralized clearinghouse to facilitate buying and selling of local and flexible RA capacity. (IEP Proposal at 10, IEP Comments at 11.) Shell agrees that the Commission should develop an electronic bulletin board for RA, which it argues would provide transparency and increased liquidity. (Shell Comments at 11.) The CCA Parties also recommend that either the Commission or CAISO make a bulletin board available to LSEs. (CCA Parties Comments at 8.) LSEs are already able to use an electronic bulletin board operated by PJM. However, it is unclear from party comments why this bulletin board is insufficient, or what changes might improve it. The possible replacement or expansion of this bulletin board may be considered in Track 2.

AReM argues that existing procurement rules may create impediments to RA contracting, and recommends that utilities be allowed to enter into RA transactions of up to one year in length without procurement review group (PRG) review. (AReM Proposal at 9.) Shell makes a similar argument, that PRG review requirements may be causing the utilities to hold, rather than sell, capacity. (Shell Comments at 8.) TURN, however, argues that current procurement rules do not constrain the utilities' ability to sell capacity, and that parties should cite the specific rules they believe are problematic in order to build a record for further discussion. (TURN Reply Comments at 6.) We note that D.15-10-031 and D.16-01-015 already provide for exceptions to the procurement requirements, including an exception for transactions that were executed according to processes reviewed by the PRG.

AReM's proposal does not specify which provisions of existing procurement rules it contends are preventing the utilities from executing certain transactions, and none of the utilities commented on AReM's proposal (or on Shell's related concern). It is not clear from the record that existing procurement rules and standards are insufficient, and accordingly we do not adopt AReM's proposal at this time.

In R.14-10-010, Energy Division staff and the Joint DR Parties each proposed that the Commission not impose a response time requirement on local RA resources at that time. In response, the CAISO recommended that the Commission "align" the RA requirements with CAISO's Local Capacity Technical Study by requiring that all resources meet one of two requirements in order to qualify for local RA: 1) be able to respond within 20 minutes, or 2) have sufficient energy available for frequent pre-contingency dispatch.

D.16-06-045 indicated that it supported the CAISO's objectives, but suggested that it would be necessary: "to define the implementation details of the CAISO's proposed requirements for local RA resources before new requirements become effective." (D.16-06-045 at 36.) D.16-06-045 requested that, "the CAISO work collaboratively with parties and Staff to develop clear tariff rules and practices around pre-contingency dispatch of DR resources to count for local RA capacity through an open and transparent CAISO stakeholder initiative process," (*Id*.) and following that process, develop clear recommendations to the Commission on the following:

- Necessary program tariff and contract modifications and/or new provisions to enable pre-dispatch of local RA resources, including contract provisions related to the minimum required number of pre-dispatches per year, based on the CAISO estimates of total pre-dispatch need in each local area,
- Any other modifications to policy or rules necessary to ensure that DR resources can qualify as local RA, based on a non-discriminatory application of those rules.

On February16, 2018, the CAISO proposed to set 2020 LCR consistent with the transmission planning analysis discussed in its proposal. The CAISO proposed that it would update its analysis in the 2020 local capacity technical study (which it will perform in 2019), and that this analysis would identify the maximum level of use-limited capacity in each local area and sub-area. In addition, CAISO indicated that it "will discuss in stakeholder initiative ways to allow pre-dispatch of slow response PDR prior to the contingency." (CAISO Proposal at 17.)

Numerous parties commented on CAISO's proposal,[20] with most suggesting that additional work needs to be done. NRG states that, "[t]his is a critically important topic, and much more work is needed to be able to assign reliable local capacity values to use-limited preferred resources." (NRG Comments at 15.) The Joint DR Parties "also agree that the issue should continue to be studied and refined in future RA proceedings." (Joint DR Parties Comments at 7). CLECA recommends that this issue be considered in Track 2. (CLECA Comments at 2.) And "SCE believes that further work should be done to understand the study results and how to apply them to the RA framework." (SCE Comments at 7). ORA suggests that it is "premature to adopt CAISO's undefined methodology" and that the issue "should be further addressed in Track 2 where CAISO can clearly define the methodology it seeks the CPUC to adopt, the impact of the proposal on current use-limited resources and the associated changes for future procurement." (ORA Comments at 20-21.)

Many parties suggest that further works needs to be done. We agree, and anticipate further record development in Track 2 and Track 3 of this proceeding.

4. Comments on Proposed Decision

The proposed decision of Administrative Law Judges Allen and 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 [______].).

5. Assignment of Proceeding

Liane Randolph is the assigned Commissioner and Peter V. Allen and Debbie Chiv are the assigned Administrative Law Judges in this proceeding.

[20] ORA Comments at 20 – 21, NRG Comments at 15, Joint DR Parties Comments at 7, SCE Comments at 7, CEERT Comments at 3, Calpine Comments at 16-17, SDG&E Comments at 11-12,and CESA Comments at 5.

Findings of Fact

1. The CAISO recommended a total LCR for all local areas of 25244 MW for 2019.
2. Because of resource deficiencies totaling 640 MW, the existing capacity needed for LCR for 2019 is 24604 MW.
3. The CAISO is recalculating its FCR figures for 2019, and the new figures will not be available in time to be incorporated in this decision.
4. The Commission previously approved FCR figures for 2018.
5. There is not an adequate basis for implementing changes to the flexible RA methodology in Track 1.
6. There is not an adequate basis for implementing changes to the system RA methodology in Track 1.
7. Energy Division recommended that all LSEs participate in all aspects of the year-ahead RA process if they seek to serve load in the following calendar year.
8. The requirement that all LSEs participate in all aspects of the year-ahead RA process will reduce unexpected intra-year load migration.
9. It is premature and unnecessary to introduce an interim mechanism for reallocating collective deficiency Capacity Procurement Mechanism costs to account for intra-year load migration.
10. Implementation of monthly adjustments to local and flexible RA requirements to account for intra-year load migration is both unnecessary and overly burdensome for Commission staff resources at this time.
11. Continued use of the waiver option established by Resolution E-4907 beyond 2018 may undermine the annual RA program.
12. Of the CCAs who are utilizing the waiver option under Resolution E-4907, none have chosen to exercise Option B.
13. A multi-year RA requirement can provide cost and reliability benefits.
14. It is premature to fully implement a multi-year RA requirement for 2019.
15. A central buyer system can provide cost and reliability benefits.

16. It is premature to fully implement a central buyer structure for 2019.

17. Further studies would help to set multi-year procurement requirements and optimize resource selection.

18. Utility contracts with needed generation facilities may be less expensive than backstop procurement mechanisms.

19. Bringing the CAISO's AAH and the Commission's RA measurement hours into alignment would reduce confusion and uncertainty among resource owners and reduce the potential for double procurement.

20. Requiring the submission of the CAISO's annual AAH analysis into the RA proceeding for consideration by the Commission gives parties an opportunity to comment on any revision of hours.

21. The modification of the RA measurement hours to HE17-HE21 (4:00 p.m. - 9:00 p.m.), to align with the CAISO's AAHs, is reasonable.

22. There is no good policy or legal basis for continuing to exclude combined storage and DR projects from being eligible to participate in the RA program.

Conclusions of Law

1. The CAISO's recommended LCR should be adopted.

2. The record of the proceeding lacks usable FCR numbers for 2019.

3. Previously adopted 2018 FCR numbers should continue to be used until usable 2019 numbers are available.

4. A process for considering and adopting updated FCR numbers for 2019 should be adopted.

5. Changes to the flexible RA methodology should not be adopted at this time.

6. Changes to the system RA methodology should not be adopted at this time.

7. Participation in the year-ahead RA process by all LSEs who plan to serve load in the following year, including accurate forecasting of expanded territory or customer base, should ensure a more equitable allocation of the RA requirements.

8. An interim mechanism for reallocation of collective deficiency CPM costs that account for intra-year load migration should not be adopted at this time.

9. A requirement to adjust local and flexible RA requirements on a monthly basis to account for intra-year load migration should not be adopted at this time.

10. The waiver process established by Resolution E-4907 should not be extended beyond 2018.

11. A cost allocation formula for Waiver Option B under Resolution E-4907 should not be adopted.

12. Implementation of multi-year RA requirements should be initiated for 2020.

13. Implementation of a central buyer structure for multi-year local RA requirements should be initiated for 2020.

14. Further study should be initiated to develop multi-year local RA requirements and guide multi-year local RA procurement.

15. Utilities should be encouraged to negotiate cost-effective contracts with generation facilities that may otherwise utilize backstop procurement mechanisms.

16. The CAISO's annual AAH analysis should be submitted into the RA proceeding for consideration as to whether the Commission should adjust its RA measurement hours.

17. The RA measurement hours should be modified to HE17-HE21 (4:00 p.m. - 9:00 p.m.) for each month of the year beginning in 2019.

18. Combined storage and DR projects should be eligible to participate in the RA program.

O R D E R

IT IS ORDERED that:

1. The Commission approves 24604 megawatts as the existing capacity needed for the Local Capacity Requirement for 2019.

2. The existing Flexible Capacity Requirement amounts for 2018 remain in effect until recalculated 2019 numbers are adopted.

3. When the California Independent System Operator files and serves its final Flexible Capacity Requirement report in this proceeding, parties have until the end of the third business day after the date of service to file and serve responsive comments.

4. All load serving entities shall procure system capacity consistent with the pre-existing methodology.

5. All load serving entities shall participate in all aspects of the year-ahead RA process for load they plan to serve in the following year.

6. An interim mechanism for reallocation of collective deficiency Capacity Procurement Mechanism costs is not adopted at this time.

7. A proposal to adjust local and flexible resource adequacy requirements on a monthly basis is not adopted at this time.

8. The waiver process established by Resolution E-4907 will not be extended beyond 2018.

9. A cost allocation formula for Waiver Option B under Resolution E-4907 is not adopted.

10. In their Track 2 testimony parties should propose a multi-year local resource adequacy requirement with a three-to-five-year duration.

11. In their Track 2 testimony parties should propose central buyer structures for multi-year local resource adequacy procurement, consistent with this decision.

12. The California Independent System Operator Corporation's annual availability assessment hour analysis will be submitted into the resource adequacy proceeding for consideration as to whether the Commission should adjust its resource adequacy measurement hours.

13. The resource adequacy measurement hours are modified to HE17-HE21 (4:00 p.m. – 9:00 p.m.) for each month of the year beginning in 2019.

14. Combined storage and demand response projects are eligible to participate in the Resource Adequacy program.

15. This proceeding remains open.

This order is effective today.

Dated ______________________________, at San Francisco, California.