Decision 16-06-045 June 23, 2016

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 2016 and 2017 Compliance Years.	Rulemaking 14-10-010 (Filed October 16, 2014)

TRACK 1 DECISION ADOPTING LOCAL AND FLEXIBLE CAPACITY OBLIGATIONS FOR 2017, AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

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TRACK 1 DECISION ADOPTING LOCAL AND FLEXIBLE CAPACITY OBLIGATIONS FOR 2017, AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

Summary

This decision adopts local and flexible capacity obligations for 2017 applicable to Commission-jurisdictional electric load serving entities and makes certain changes to the Resource Adequacy (RA) program.

The local procurement obligations are based on annual studies of local capacity and flexible capacity requirements performed by the California Independent System Operator (CAISO) for 2017 which seek to ensure that each part of the CAISO controlled grid, including those parts with transmission constraints, have access to sufficient generating capacity to meet the local need. The total local capacity requirements recommended by the CAISO, and adopted herein for all local areas, decreased slightly from the prior year; the total of all local areas decreased from 25,341 megawatts (MW) in 2016 to 24,549 MW in 2017.

The CAISO's recommended flexible capacity requirement is also adopted. The Commission-jurisdictional 2017 flexible capacity requirements range from 9,292 MW (August 2017) to 14,425 MW (November 2017). The flexible capacity needs increased substantially from those identified by the CAISO and adopted by the Commission for 2016. Much of this change was due to the inclusion of additional solar production in this year's study.

The Energy Division has made tremendous progress in using Effective Load Carrying Capacity modeling to evaluate the capacity value of wind and solar resources, however, significant challenges remain in this area. We anticipate continued progress, and hope to adopt this approach for 2018.

The CAISO recommends that we implement requirements that all local RA resources be required to either: 1) respond within 20 minutes; or 2) have sufficient energy for pre-contingency dispatch. We find that these proposed requirements are reasonable, but that significant effort is required to implement the details in an appropriate and non-discriminatory manner. We adopt a process to ensure the sound implementation of these requirements, and intend to review success of the efforts in a future RA decision.

1. Background

Pub Util. Code § 380 (as amended)[1] requires that "the commission, in consultation with the California Independent System Operator (CAISO or ISO), shall establish resource adequacy requirements for all load-serving entities." The statute establishes a number of objectives for the Commission to achieve with the resource adequacy (RA) program, including development of new generating capacity and retention of existing generating capacity, equitable allocation of the cost of generating capacity, and minimization of enforcement requirements and costs. Section 380(j) defines "load serving entities" for purposes of this section as "an electrical corporation, electric service provider, or community choice aggregator."

Based on the statutory language, the Commission's RA program and its requirements apply to all load serving entities (LSEs) under our jurisdiction. Certain small or multi-jurisdictional LSEs are subject to different RA requirements which are more appropriate to their situations than those described in this order.

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

In June 2015, we issued Decision (D.) 15-06-063 which decided issues in Phase 1 of this proceeding. That decision also provides procedural background up to that point, in this Rulemaking.

On December 7, 2015 the Administrative Law Judge (ALJ) and assigned Commissioner held a prehearing conference to discuss remaining issues; on December 23, 2015, the Assigned Commissioner and Administrative Law Judge's Phase 2 Scoping Memo and Ruling (Phase 2 Scoping Memo) was issued. The Phase 2 Scoping Memo initiated two separate tracks for Phase 2 and stated that the focus of this Track 1 decision "will be to adopt local RA capacity requirements (LCR) and flexible capacity requirements (FCR) for RA compliance year 2017." The Phase 2 Scoping Memo also stated that this Track 1 Decision "may also adopt refinements to the RA program, and will consider proposals from Energy Division and parties for such refinements."[2]

On January 15, 2016 several parties filed and served proposals for consideration. The proposals and questions of the Energy Division were submitted the same day by ALJ Ruling. Parties filed and served comments on the staff and party proposals on January 29, 2016. Energy Division facilitated a workshop on the proposals on February 18, 2016. Following the workshop, parties were allowed to file and serve revised proposals on March 25, 2016. Comments and reply comments on the revised proposals were filed and served April 1 and April 8, 2016, respectively.

The following parties participated in the process of proposals and comments described above, by filing and serving comments, reply comments,

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[2] Phase 2 Scoping Memo at 2.

and/or proposals: Alliance for Retail Energy Markets (AReM); Calpine Corporation (Calpine); CAISO; California Energy Storage Alliance (CESA); California Large Energy Consumers Association (CLECA); City of Lancaster; Direct Access Customer Coalition (DACC); EnerNOC, Inc. (EnerNOC), Johnson Controls, Inc., Comverge, Inc., and CPower[3] (together, the Joint DR Parties); Green Power Institute (GPI); Large-Scale Solar Association; Marin Clean Energy (MCE); NRG Energy, Inc. (NRG); Office of Ratepayer Advocates (ORA); Pacific Gas and Electric Company (PG&E); Shell Energy North America (US), L.P. (Shell); Sonoma Clean Power Authority (SCPA); Southern California Edison Company (SCE); San Diego Gas & Electric Company (SDG&E); SolarCity Corporation (SolarCity); and The Utility Reform Network (TURN).

The remaining portion of Track 1 focused on adopting LCR and FCR for RA compliance year 2017. To this end, CAISO filed and served its 2017 Local Capacity Technical Report (2017 LCR Study) and Flexible Capacity Needs Assessment for 2017 (2017 FCR Study) on April 29, 2016. TURN and PG&E filed and served comments on the 2017 LCR and FCR Study on May 6, 2016. CAISO filed and served reply comments on May 10, 2016.

2. Safety Issues

The RA program is directly concerned with reliability, and reliability is closely connected with safety. Maintaining electric reliability promotes the public health and safety in important ways, and the RA program contributes to providing this benefit to Californians. No participants at the prehearing

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[3] Note that, during the course of this proceeding, Johnson Controls, Inc. became a subsidiary of CPower.

conference recommended any direct safety considerations for the scope of this proceeding, and none have arisen since that time.

3. Local Capacity Requirements (LCR) for 2017

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. D.07-06-029, D.08-06-031, D.09-06-028, D.10-06-036, D.11-06-022, D.12-06-025, D.13-06-024, D.14-06-050, and D.15-06-063 established local procurement obligations for 2008 through 2016, respectively. The RA program has been refined each year since 2007. The local RA program and associated regulatory requirements adopted in those decisions continue in effect for 2017 and thereafter until changed, subject to the 2017 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 calculated based on an LSE's "system" peak load plus a 15% planning reserve margin. "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. Following a stakeholder process, the CAISO posted its 2017 LCR Study on its website, served notice of the report's availability, and filed it with the Commission on April 29, 2016.

The CAISO states that the assumptions, processes, and criteria used for the LCR study were discussed and recommended in a stakeholder meeting, and that, on balance, they mirror those used in the 2007 through 2016 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 summarizes the changes from 2016 to 2017:

> Overall, the LCR needs have decreased by about 790 MW or about 3.1% from 2016 to 2017. The LCR needs have decreased in the following areas: Humboldt, Stockton, Fresno and Big Creek/Ventura due to downward trend for load; LA Basin due to downward trend for load and new transmission projects. The LCR needs have increased in North Coast/North Bay due to lower requirement in the Pittsburg sub-area of the Bay Area; Sierra due to increase in deficiency; Bay Area due to new South Bay-Moss Landing sub-area requirements and increase in San Jose sub-area deficiency; Kern due to additional load (about 280 MW) triggered by re-definition to account for the new 230 kV binding constraint and San Diego/Imperial Valley due to cancellation of previously planned upgrade projects connecting to the Imperial Valley 230 kV substation.[4]

CAISO's recommended 2017 LCR are summarized in the following table. We also provide the 2016 LCR for comparison.

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[4] 2017 LCR Study at 3.

2017 Local Capacity Requirements									
	Qualifying Capacity			2017 LCR Need Based on Category B			2017 LCR Need Based on Category C with Operating Procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	20	198	218	110	0	110	157	0	157
North Coast / North Bay	128	722	850	721	0	721	721	0	721
Sierra	1176	890	2066	1247	0	1247	1731	312*	2043
Stockton	149	449	598	340	0	340	402	343*	745
Greater Bay	1070	8792	9862	4260	232*	4492	5385	232*	5617
Greater Fresno	231	3072	3303	1760	0	1760	1760	19*	1779
Kern	60	491	551	137	0	137	492	0	492
LA Basin	1615	8960	10575	6873	0	6873	7368	0	7368
Big Creek/ Ventura	543	4920	5463	1841	0	1841	2057	0	2057
San Diego/ Imperial Valley	239	5071	5310	3570	0	3570	3570	0	3570
Total	5231	33565	38796	20859	232	21091	23643	906	24549

* 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.

2016 Local Capacity Requirements									
	Qualifying Capacity			2016 LCR Need Based on Category B			2016 LCR Need Based on Category C with Operating Procedure		
Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	21	208	229	118	0	**118**	167	0	**167**
North Coast / North Bay	132	735	867	611	0	**611**	611	0	**611**
Sierra	1195	831	2026	1139	16*	**1155**	1765	253*	**2018**
Stockton	160	434	594	357	0	**357**	422	386*	**808**
Greater Bay	1104	6435	7539	3790	0	**3790**	4218	131*	**4349**
Greater Fresno	282	2647	2929	2445	0	**2445**	2445	74*	**2519**
Kern	99	430	529	214	0	**214**	400	0	**400**
LA Basin	1710	9259	10969	7576	0	**7576**	8887	0	**8887**
Big Creek/ Ventura	584	4951	5535	2141	0	**2141**	2398	0	**2398**
San Diego/ Imperial Valley	228	4687	4915	2850	0	**2850**	3112	72*	**3184**
Total	**5515**	**30617**	**36132**	**21241**	**16**	**21257**	**24425**	**916**	**25341**

* 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.

No party contests the conclusions of the CAISO's 2017 LCR Study. We have reviewed the 2017 LCR Study and find it to be reasonable. We adopt the CAISO's recommendations as the basis for establishing local procurement obligations for 2017 applicable to Commission-jurisdictional LSEs.

In previous decisions, we delegated ministerial aspects of RA program administration to the Commission's Energy Division. Once again, Energy Division should implement the local RA program for 2017 in accordance with the adopted policies.

3.1. Aliso Canyon and San Diego Sub-Area Requirements

Due to the ongoing concern about availability and operation of the Aliso Canyon gas storage facility, the 2017 LCR Study "balanced the gas generation resource needs in the LA Basin and the San Diego sub-area." Given the shift in required resources, the binding constraint in the San Diego sub-area is the same as that in LA Basin. This change reduces the LA Basin requirement by 716 MW and increases the San Diego sub-area (not San Diego – Imperial Valley area overall) requirement by 865 MW.[5]

TURN suggests that we should track changes in procurement costs resulting from this shift. TURN contends that total costs may be higher because 1) the added need in San Diego sub-area is greater than the reduction in LA Basin, and 2) SCE has likely already contracted for much of the LA Basin requirement so that there will be no meaningful savings associated with the LA Basin reduction. TURN recommends that we order SCE and SDG&E to track the effects of the shift so that we can later consider holding Southern California Gas Company shareholders responsible for increased costs.

In comments on the proposed decision, SDG&E contends that the portion of the shift in requirements from LA Basin to San Diego sub-area due to Aliso Canyon is 274 MW in LA Basin and 172 MW in San Diego sub-area and that only these lower amounts should be tracked. SDG&E notes that CAISO also discusses a "peak shift issue associated with the impact of behind the meter solar

[5] See 2017 LCR Study at 87-90 and 108-109.

generation."[6] In reply comments, CAISO supports SDG&E's understanding of the 2017 LCR Study, but TURN opposes SDG&E's interpretation. The 2017 LCR Study states:

> This [solar peak shift] sensitivity assessment resulted in a San Diego sub-area local capacity need of approximately 2,743 MW, approaching the level of the rebalancing of resources to support mitigating the loss of the Aliso Canyon gas storage facility as discussed in the sections below. The LCR need for the LA Basin associated with this sensitivity voltage stability assessment is 7,094 MW. In light of this, the requirements are being set based on the Aliso Canyon discussion below.[7]

As TURN, notes, we have not adopted, and CAISO has not formally proposed, any changes to LCR methods to reflect the potential peak shift. Therefore, we interpret the language quoted above literally: the peak shift sensitivity is only a sensitivity assessment, and the requirements are "set based on the Aliso Canyon discussion." We do not consider the peak shift sensitivity to be the relevant point of comparison for the LCR requirements in the absence of the Aliso Canyon concerns. Therefore, we use the larger numbers (716 MW decrease in LA Basin and 865 MW increase in San Diego sub-area) suggested by TURN; this is the magnitude of the shift attributable to Aliso Canyon concerns.

Cost recovery issues related to Aliso Canyon are not in scope of this proceeding. However, we need not address cost recovery to conclude that tracking these costs is appropriate to inform future decisions in RA as well as potential cost recovery decisions. As noted by CAISO, it is not clear how long

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[6] 2017 LCR Study, pg 87.

[7] 2017 LCR Study, pg. 88.

the operation of Aliso Canyon will be constrained. Future LCR Studies and RA decisions may need to address changes to the local RA program in response to Aliso Canyon. Therefore, we take two actions in response to TURN's comments.

First, as TURN suggests, we direct SDG&E and SCE to file and serve Tier 2 advice letters establishing appropriate mechanisms to track changes in local RA costs resulting from the shift in local RA obligations from LA Basin to the San Diego sub-area. If practical, SDG&E and SCE are encouraged to coordinate their tracking mechanisms to aid our review of these cost changes. These Tier 2 Advice Letters shall be filed within 30 days of the effective date of this decision.

Second, we ask the CAISO to provide analysis of potential, responsive changes to the local RA program in the 2018 LCR Study, if Aliso Canyon operations continue to be constrained. For example, we ask CAISO and interested parties to consider whether merging the LA Basin and San Diego local areas is appropriate in order to best allocate costs and maintain reliability. We thank the CAISO for its commitment to "continue to monitor the status of the Aliso Canyon storage facility and any implications it may have on local reliability issues"[8] and ask the CAISO to share its analysis with this Commission through the RA proceeding and other forums. In particular, we ask that the results of this analysis, including any analysis addressing the potential impacts of merging the LA Basin and San Diego local areas, be raised in the 2018 RA proceeding. The 2018 LCR Study may address these subjects, but any major proposed changes (e.g. merging local areas and/or relying on a peak shift analysis) should be considered publically well in advance of the final LCR study.

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[8] CAISO Reply Comments at 3.

4. Flexible Capacity Requirements (FCR) for 2017

D.13-06-024 and D.14-06-050 adopted a flexible capacity requirement to begin in 2015 and defined guidelines for its implementation. D.15-06-063 also 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."[9]

D.13-06-024 also adopted the following formula to calculate system flexibility requirement:

> Flexibility NeedMTHy = Max [(3RRHRx) MTHy]+ Max(MSSC, 3.5%*E(PLMTHy)) + ε
>
> Where,
>
> Max [(3RRHRx) MTHy] = Largest three hour continuous ramp starting in hour x for month y
>
> E(PL) = Expected peak load
>
> MTHy = Month y
>
> MSSC = Most Severe Single Contingency
>
> ε = annually adjustable error term to account for uncertainties such as load following.

Following a stakeholder process, the CAISO filed its 2017 FCR Study in this proceeding on April 29, 2016. No party filed comments contesting the results of the CAISO's 2017 FCR Study.

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

Based on its analysis, the CAISO identified the maximum flexible capacity needs for each month of 2017 (*see* table below). The flexible capacity needs are greatest in non-summer months and range from 9,918 MW (August 2017) to 14,977 MW (November 2017). The flexible capacity needs increased substantially from those identified for 2016, which in turn were greater than 2015 needs. Much of this change was due to continuing increase in solar production in each year's study. As illustrated in the table below, most of the flexible capacity needs are allocated to CPUC-jurisdictional load serving entities (ranging from 89% in April to 98% in December).

2017 Flexible Capacity Needs

NOTE: All numbers are in Megawatts	CAISO System Flexible Requirement	CPUC Flexible Requirement	CPUC		
			Category 1 (minimum)	Category 2 (100% less Cat. 1 & 3)	Category 3 (maximum)
January	14,110	13,281	6,687	5,930	664
February	12,840	12,238	6,162	5,464	612
March	13,456	12,918	6,504	5,768	646
April	13,220	11,764	5,923	5,253	588
May	12,043	11,600	7,462	3,558	580
June	10,939	10,290	6,619	3,156	515
July	9,995	9,366	6,025	2,873	468
August	9,918	9,292	5,977	2,850	465
September	11,525	10,501	6,755	3,221	525
October	11,514	10,761	5,418	4,805	538
November	14,977	14,425	7,263	6,441	721
December	14,588	14,276	7,188	6,374	714

In addition, the CAISO divides the flexible capacity needs into three categories. These categories are defined based on the CAISO's assessment of the different types of flexible capacity needed to address the CAISO's needs. Specifically, in the "flexible resource adequacy criteria and must offer obligation" (FRAC-MOO) stakeholder initiative, the CAISO adopted the following flexible capacity categories:

> Category 1 (Base Flexibility): Operational needs determined by the magnitude of the largest 3-hour secondary ramp.
>
> Category 2 (Peak Flexibility): Operational needs determined by the difference between 95% of the maximum 3-hour net-load ramp and the largest 3-hour secondary net-load ramp.
>
> Category 3 (Super-Peak Flexibility): Operational needs determined by 5% of the maximum 3-hour net-load ramp of the month.

While the CAISO has identified the flexible capacity needs by category and by month, the CAISO established the requirements on a seasonal basis. Accordingly, the CAISO proposes percentage maximum or minimum limits for different categories of flexible resources applicable to summer (May - September) and winter (all other months) months. The application of these percentage limits on categories of flexible resources to Commission-jurisdictional entities is shown in the table above.

We have reviewed the CAISO's Final Flexible Capacity Needs Assessment for 2017 and find it to be reasonable. We adopt the CAISO's recommendations as the basis for establishing flexible procurement obligations for 2017 applicable to Commission-jurisdictional LSEs.

5. Local and Flexible Capacity Requirements Studies for Future Years

TURN has expressed serious concerns with the process leading to the LCR Study for 2017. TURN's concerns focus on the removal of draft studies from the CAISO website, without notice. TURN concludes that CAISO's process was "less than transparent" and recommends that we seek transparency for future years.

In response, CAISO notes that because of the removal of the draft it extended the comment period and asserts that there was no prejudicial impact.

Similarly, PG&E argues that important wind and solar data were omitted from the 2017 FCR study and that the magnitude and impact of those omissions are not explained. PG&E recommends that we "require" the FCR study to include those explanations. In their absence, PG&E states that it supports the method of the FCR study, but cannot recommend that we adopt the outcome due to the unacceptable lack of information.

CAISO responds that the magnitude of omitted data is very small in comparison to the overall flexibility requirements, and that therefore, there was no material impact of the omission. CAISO states its intent to proactively obtain any missing information in 2018 and future studies.

Additionally, PG&E requests that the CAISO include additional explanation of how busbar level demand response (DR) information is used in future LCR Studies. This request is consistent with our emphasis on transparency discussed in Section 7.1.4., below.

In response, CAISO explains that it intends to evaluate these data for use in the 2018 LCR Study, among other forums. CAISO requests that PG&E raise this issue in the 2018 LCR Study process.

In most years, the LCR Study and FCR Study results have been uncontested. Even in the event that the results of the LCR and FCR Studies are non-controversial, the timelines of recent RA proceedings (Studies in late April or early May, proposed decision in mid- or late-May, final decision in June) leaves very little time for review of the Studies' results by the CPUC and parties in the RA proceeding.

In order to ensure that we are able to provide due process to all parties, we request that in future LCR and FCR studies, the CAISO promote an open and transparent process. In particular, we request that the CAISO adhere to the following guidelines:

- All draft studies should be posted to the CAISO website when they are released,
- Posted drafts should remain publically accessible for the duration of the process,
- All comments on draft studies should be posted to the CAISO website soon after they are received,
- If necessary due to confidentiality concerns, commenting stakeholders should be encouraged to submit public and confidential versions of their comments,
- Draft and final studies should describe and address the impact of any data that was not available to the CAISO to perform the study,
- Work papers supporting the final studies should be shared with Energy Division staff as necessary to implement the RA program,
- The final studies should include a response to comments,
- The final studies should be filed and served in the then-current RA proceeding by April 15 of each year, unless otherwise scheduled by the ALJ or scoping memo, and
- The final LCR study should include an explanation of the role of DR, including busbar level data provided by the utilities.

6. Effective Load Carrying Capacity (ELCC) Proposals

Pursuant to § 399.26(d), Energy Division staff has developed a proposal for measuring the Effective Load Carrying Capacity (ELCC) of wind and solar resources for purposes of the RA program. ELCC is a statistical modeling approach to determine the capacity value of different resources relative to "perfect capacity." For example, if removing 100 MW of solar resources from the grid and replacing it with 50 MW of perfect capacity results in no change in the Loss of Load Expectation (LOLE), then the ELCC of the solar resources would be 50%.

Energy Division first published ELCC results on July 15, 2015, released a proposal on January 15, 2016, and released a revised proposal on March 25, 2016. In each revision, staff considered and addressed many stakeholder comments gathered through workshops and both formal and informal comments. We appreciate the considerable effort that staff and parties have invested in developing a technically sound ELCC proposal for our consideration. For clarity, we limit our review and analysis in this decision to the revised proposal issued in March and the comments on that proposal.

Although SCE's recommendation is not to implement ELCC for 2017, SCE also presented a proposal to "cap" the ELCC results based on the contribution of wind and solar resources to reducing the peak of net load.

Both proposals are discussed below. Parties generally agree that, although there has been great progress in ELCC efforts, ELCC should not be implemented for 2017.

6.1. Energy Division Proposal

Energy Division used a commercially available model called Strategic Energy Risk Valuation Model (SERVM), with assistance from Astrape Consulting. SERVM uses a stochastic analysis approach, meaning that many model "runs" are studied with potentially different outcomes driven by different random values of the stochastic (random) variables. The stochastic variables represent the status of various electric system elements, such as a forced outage on a specific generation or transmission asset. Energy Division studied 200 runs in order to achieve convergence of the modeling results, meaning that studying one additional run (with different values of the stochastic variables) would not materially change the average results.

For modeling purposes, Energy Division used a reliability standard of 0.1 LOLE (i.e. one day in ten years); in order to achieve this reliability standard, Energy Division removed 4,716 MW of existing thermal resources from the study for modeling purposes.[10] Energy Division studied the CAISO control area for 2017 including 6,492 MW of wind and 7,424 MW of solar resources that were online before November 2015. Imports into the CAISO were also modeled, including both renewable and conventional (e.g. Palo Verde and Hoover) resources.

For load forecast modeling, Energy Division employed 33 different historical annual load shapes, but scaled them to match 2017 peak and total energy by region for the July 7, 2015 draft California Energy Commission's Mid Demand, Mid Additionally Achievable Energy Efficiency (AAEE) load forecast.[11] To scale the load shapes to match the peak load and annual energy (GWh) forecasts, Energy Division performed a linear transformation of each historic load shape to match the target peak load and annual energy. As a result, not all

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[10] These resources are specifically identified in Energy Division's study at Table 3. Note that this list of resources should not be interpreted to suggest that either Energy Division or the Commission forecasts that any of these resources will or will not be available at any specific future date. Inclusion on (or exclusion from) this list has no bearing on any resource's 2017 or later net qualifying capacity (NQC), effective flexible capacity (EFC), or other RA attributes.

[11] See: California Preliminary Demand Forecast, Mid Demand: http://www.energy.ca.gov/2015_energypolicy/documents/2015-07-07_preliminary_forecast_forms.html

hours were scaled equally. The only three load shapes with modeled LOLE values on the CAISO system in excess of 0.01 were 2009, 1998, and 2006.

6.1.1. Differentiation Between Technology Types and Regions

In early stages of the modeling process, various parties requested that Energy Division differentiate the results of the ELCC study between different resource technology types (e.g. photovoltaics vs. solar thermal) and regions (e.g. Northern and Southern California). Energy Division did not present results with differentiation between technology types more specifically than wind and solar. Energy Division disaggregated solar ELCC into Northern and Southern California regions, but has not yet presented results for wind locational factors. All other technology or regional sub-classifications were not differentiated further.

Energy Division faced a challenge of separating out the effects of location from the effects of penetration level. In general, studies show that an increase in solar penetration leads to a decrease in the ELCC of solar generation. Energy Division staff sought to test the effects of similar quantities of solar generation in Northern and Southern California, first by removing all solar generation in California and adding back equal quantities to each area in California, then by adding back all the solar generation in California and removing equal quantities of solar generation in each area of California. That resulted in locationally relative marginal ELCC values that were comparable in that the marginal ELCC results represented marginal ELCC at the same level of solar penetration. When results of these tests were completed, study results revealed that the average value of both the first block and last block of solar generation in southern

California were greater than the ELCC value of the first and last block of solar generation in northern California.

6.1.2. Differentiation Between Months

As Energy Division explains, ELCC studies are typically performed to measure the annual capacity values of various resources. Therefore, Energy Division developed an adaptation of the ELCC approach in order to be consistent with the monthly RA obligations and monthly NQC values of the existing RA program.

Energy Division attempted to simulate the conditions of each calendar month individually by adjusting the capacity of non-nuclear thermal generators, while modeling the constant capacity of renewable, hydro, and nuclear resources. For each month, Energy Division employed the relevant month-specific generation profiles for the renewable and hydro resources. In effect, this approach studies the impact of the different relative proportions of the various energy sources each month.

6.1.3. Phase-In Over Time

Energy Division proposes to phase in the ELCC values over three years for purposes of determining NQC. For 2017, NQC would be based on a one-third weighted ELCC value and a two-thirds weighted exceedance value. By 2019, ELCC would entirely determine NQC.

6.2. SCE's Net Load Peak (NLP) Proposal

SCE recommends that ELCC should not be adopted at this time. As a secondary recommendation, SCE suggests that NQC determined by ELCC should be capped based on a method it describes as Net Load Peak based ELCC (NLP-ELCC).

SCE's primary stated concern with Energy Division's ELCC proposal is that the ELCC proposal might result in too little RA capacity procurement to meet peak load or net peak load, particularly in winter months. SCE's intent with NLP-ELCC is to determine the highest capacity value that wind and solar resources could have while "maintaining the requirement that there will be enough resources to meet load in all hours of a month." The NLP-ELCC is based on subtracting the peak load net of wind and solar generation (i.e. NLP) from the peak gross load. SCE surmises that there must be enough other (i.e. non-wind, non-solar) RA resources available to meet the NLP. Therefore, wind and solar NQC should not exceed the difference between NLP and peak gross load, and SCE proposes to cap ELCC accordingly.

6.3. Positions of Other Parties

While parties are generally supportive of Energy Division's and SCE's modeling efforts, several parties recommend that we should implement neither the Energy Division proposal nor the SCE proposal at this time. Only Calpine and CalWEA recommend that we implement ELCC for 2017.

Generally, parties contend that the parties and the Commission need more time to adequately understand the results of the ELCC proposals and resolve questions. Parties note concerns with various assumptions (e.g. load forecasts) as well as modeling choices (e.g., which resources are removed for analytic purposes). Further, some parties raise concerns with the basic ELCC approach such as the comparison of generators to "perfect capacity." The parties who recommend we do not implement ELCC at this time include: CAISO, CLECA, LSA, PG&E, SCE, SDG&E, and TURN. Similarly, ORA notes that it has outstanding concerns that it wishes to see resolved before implementation.

Several of these parties suggest ideas for continuing Energy Division modeling work, including:

- Further technological differentiation,
- Consideration of curtailed generation,
- Further detail on incremental value estimates, particularly by location,
- Further analysis of monthly values,
- Analysis of future imports and load shapes, and
- Explicit representation of behind-the-meter resources.

Parties also offer suggestions for next steps in SCE's efforts. SDG&E observes that a stochastic load forecast may be a worthwhile improvement to SCE's proposed NLP-ELCC approach. First, SCE's method likely undervalues the contributions of solar in a high load year because the deterministic approach relies on a 1-in-2 load forecast. Second, SDG&E contends NLP-ELCC may overvalue wind in some months. Similarly, TURN expresses concern with the 30th percentile assumption relied on by SCE and questions whether SCE's approach is actually ELCC in the sense intended by §399.26(d). TURN also contends that SCE's NLP-ELCC approach would unreasonably increase ratepayer costs. CLECA contends that SCE's NLP-ELCC does not adequately capture all information, including the variable level of wind and solar output.

Calpine claims that the current NQC method (exceedance[12]) results in an "artificial over-supply of RA capacity" and Calpine supports moving to ELCC at this time in order to reduce this over-supply. Moreover, Calpine contends that Energy Division has left out 5.8 GW of behind-the-meter solar from its analysis,

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[12] I.e. the level of production *exceeded* by a specific resource during 70% of defined hours.

and therefore that Energy Division overestimates the ELCC of solar. Calpine recommends applying Energy Division's calculated 37% incremental ELCC to 5.8 GW of solar, and applying the resulting weighted average of 49% to all solar. Calpine does not specifically address wind resources or monthly shaping of ELCC results.

In reply comments, CalWEA supports Calpine's comments and recommends that Energy Division's ELCC study, potentially with modifications, should be used for 2017. In particular, CalWEA agrees that behind-the-meter solar should be addressed and incorporated into the modeling. Further, CalWEA recommends that we consider various simplified ELCC approaches, benchmarked against Energy Division's results. CalWEA recommends that the ELCC values for RA should be the same as those developed for the Renewables Portfolio Standard (RPS) proceeding, or vice versa. Lastly, CalWEA suggests that NQC values should not change year to year.

Parties also offer certain procedural suggestions for implementing additional modeling work. Notably, SDG&E recommends that Energy Division establish a working group to vet and advance modeling efforts, including both staff's approach and SCE's approach.

6.4. Existing Rules Continue for 2017

We agree with most parties that despite the great work by Energy Division and parties, there are still significant outstanding questions about the ELCC proposals before us. There are real challenges that remain to be resolved before this approach can be adopted in our RA program, and therefore we do not adopt ELCC for 2017 and instead leave the existing NQC rules in place for wind and solar resources. We anticipate that these challenges will be resolved in the coming year, and we will be able to adopt ELCC for 2018.

In our view, the origin of these challenges is that the existing RA framework is not directly compatible with existing ELCC techniques. While we agree with parties that Energy Division has performed admirable modeling work, we acknowledge that Energy Division faces the unenviable task of metaphorically fitting the square peg into the round hole.

In theory, ELCC is one step in how an integrated resource planner should evaluate potential marginal changes in the generation fleet of a vertically integrated system. Such a planner does not need to allocate credit to individual existing resources at all, let alone on a monthly basis. Instead, the integrated resource planner must only use modeling results to quantitatively compare the level of reliability risk on the system given different potential generation fleets. Our current RA framework, however, is designed very differently because it is market based. Our framework requires that each and every resource has its own monthly NQC value and implicitly assumes that two different resources with the same NQC offer the same reliability benefit in the relevant month.

In the future, it is possible that we may find possible solutions to the mismatch between the existing RA framework and ELCC. However, evaluating the costs and benefits of any such solutions is not feasible based on the record of this proceeding at this time.

Like many parties, we have concerns about the method of creating shaped, monthly NQC values. In particular, the dramatic increase in the capacity value of wind and solar resources in the off-peak (winter) months relative to the current exceedance values may negatively impact reliability in those months.[13]

[13] See Energy Division Revised proposal (March 25, 2016) at 26.

Thus, we are not willing to make this change without further analysis of the reliability impacts. SCE's proposed NLP-ELCC, or some similar approach, may be a viable solution to this challenge and merits further consideration. Like TURN, we also wish to understand the ratepayer cost impacts of NLP-ELCC before adopting that approach. Alternatively, some of the simplified ELCC methods suggested by CalWEA may be appropriate.

Many parties also call for further technological or geographic differentiation of ELCC results. We agree that this is consistent with the current resource-specific NQC list. However, we are not convinced that the benefits of increasingly specific ELCC estimates justify the additional complexity. We suggest that future modeling efforts only focus on further disaggregation if it is possible to do so without relying on unfounded assumptions or overburdening the modeling effort with other complications.

Some parties appear to either misunderstand or be uncomfortable with the probabilistic nature of ELCC. We interpret these comments as primarily arising from the mismatch of ELCC in the current RA framework as described above. However, we also interpret these comments as an indication that stakeholders require more time to understand the ELCC efforts.

While we appreciate the ideas presented by parties for both substantive and procedural approaches to developing future ELCC proposals, we decline to prescribe details at this time. We encourage parties and Energy Division staff to continue to collaborate constructively on ELCC with the goal of adopting a comprehensive proposal for 2018. Further, we encourage Energy Division to continue this work expeditiously in order to realize this goal.

7. Demand Response (DR) Proposals

Several proposals for RA refinements are primarily or exclusively focused on Demand Response (DR).

7.1. Twenty (20)-Minute Response Time for Local RA Credit

Energy Division Staff and Joint DR Parties each presented proposals in this phase recommending that we not impose a response time requirement on local RA resources at this time. Staff proposed to:

> stay the course at this time and await the opportunity to design DR programs more fully for 2018 for two reasons: First the requirement regarding start times appears discriminatory. Second, the [CAISO] proposed rule could alter the value of DR resources already procured by LSEs.

In response to these proposals, the CAISO recommends that we "align" our 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. CAISO asserts these requirements are necessary for CAISO to meet NERC Planning Standards, specifically to reposition the system within 30 minutes of a contingency.[14] The two alternative requirements are that a resource must either: 1) be able to respond within 20 minutes, or 2) have sufficient energy available for frequent pre-contingency dispatch. CAISO's tariff does not define "pre-contingency dispatch," but it does define "contingency" and "dispatch."[15] In a

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[14] Even though CAISO's recommendation was not explicitly advanced as a "proposal" we treat it and refer to it as a proposal in this decision.

[15] Appendix A of CAISO's tariff provides these two definitions:

Footnote continued on next page

decision dated May 13, 2016, the CAISO deferred "implementation of [its proposed requirements for local resource adequacy resources] in order to conduct a stakeholder process focused on studying and, subject to confirmation of the adequacy of the resources, implementing pre-contingency dispatch resources to effectively resolve contingencies in compliance with applicable reliability standards and the ISO tariff."[16] The CAISO decision elaborates as follows:

> The ISO is to initiate a new stakeholder process to address implementation issues and outstanding stakeholder questions related to the pre-Contingency dispatch of resources for local reliability needs, and provide broader visibility of the analysis being conducted inside the transmission planning process. This new stakeholder process should focus on developing creative solutions to allow slower responding demand response resources to count toward local capacity requirements by enabling the ISO to use the resources prior to a first Contingency, rather than relying only on those resources capable of fast response after a first Contingency event.
>
> As part of this new stakeholder process, the ISO shall seek to conduct a joint workshop with the CPUC to address how demand response resources can help the ISO effectively address NERC, WECC and ISO reliability standards applicable to local areas. The ISO will encourage participation from all stakeholders involved in this process, but believes that collaboration with the Commission is

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Contingency: "A potential Outage that is unplanned, viewed as possible or eventually probable, which is taken into account when considering approval of other requested Outages or while operating the CAISO Balancing Authority Area."

Dispatch: "The activity of controlling an integrated electric system to: i) assign specific Generating Units and other sources of supply to effect the supply to meet the relevant area Demand taken as Load rises or falls . . ."

[16] The CAISO decision was officially noticed by ALJ ruling on May 16, 2016.

> fundamental to advancing our shared interests in integrating preferred resources and ensuring electric reliability.

In D.15-06-063, we declined to adopt a related proposal for 2016, but stated our intent to review the subject at a later time in this proceeding. We have also addressed this issue in other contexts in both a prior decision in the LTPP rulemaking and a resolution addressing DR procurement.

7.1.1. Decision 14-03-004

D.14-03-004 discussed the role of DR in meeting contingencies. In that decision, we used the terms "fast responding" or "first contingency" DR, to refer to resources with 30 minute response times. Further, in D.14-03-004, we assessed the likelihood that additional DR would be able to meet the response times required to mitigate a first contingency (30 minutes or less) in the future.[17] We stated:

> For example, demand response customers may have provisions which, when they are alerted in advance of a potential need for these resources to activate (such as a very hot weather forecast), require such resources to be activated within 30 minute when called.[18]

We further noted that,

> It is reasonable to expect that, in the future, some amount of what is now considered 'second contingency' demand response resources [meaning DR resources with response times greater than 30 minutes] can be available to mitigate the first contingency, and therefore meet LCR needs.[19]

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[17] D.14-03-004 at 53-58.

[18] D.14-03-004 at 57.

[19] D.14-03-004 FoF 47.

Although this past planning decision in no way binds our action here, we note that it indicates a policy direction consistent with the CAISO proposal. Specifically, in this decision more than two years ago, we indicated support for DR resources being able, under certain conditions, to respond quickly and aid the CAISO in repositioning the system within 30 minutes of a contingency. However, we did not directly address potential 20 minute response times and we do not rely on this past decision as a basis for reaching our conclusions in today's decision.

7.1.2. Resolution E-4754

In Resolution E-4754, we approved various Advice Letters by the IOUs, with modifications. The advice letters implemented the Demand Response Auction Mechanism II (DRAM II) pilot. Under that pilot, the IOUs are authorized to procure DR resources for 2017.

We rejected certain terms of the proposed pro forma agreements related to the 20 minute response time requirements, and modified the relevant sections. In discussion of this point, our key arguments were that: 1) the CPUC had not adopted such a 20 minute requirement, 2) that a pro forma contract in a pilot program is not an appropriate venue for resolution of conflicting regulatory requirements, and 3) a refusal to delegate our authority under §380.[20]

Here, the issue is in scope of a formal proceeding. There is a significant record before us on the subject. The simple fact that we have deferred the issue once is not a compelling reason to defer it again. In evaluating our option to change our RA rules in this proceeding, we do not create any implied delegation

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[20] Resolution E-4754 at 13.

of our §380 authority. Therefore, the reasons that led us to modify the pro forma language in the Resolution are not relevant to our consideration of this issue. Nevertheless, the existence of DRAM II and its pro forma, as modified by our Resolution, do create a valid reason not to change the rules *for 2017.* We attempt to promote regulatory certainty when it is practical to do so. Accordingly, we limit our consideration of the 20 minute rule to 2018 and forward, but we decline to again defer the issue outright.

7.1.3. Positions of Parties

Several parties responded to an ALJ ruling with questions related to the CAISO's position and provided comments on the various proposals. In response to the ALJ's questions, CAISO explains that it:

- Serves several roles under NERC rules including Transmission Operator, Planning Authority, and Balancing Authority,
- Requires 10 minutes, post contingency, to complete activities such as: identifying and implementing operating procedures, running power flow studies, determining resource needs, and sending exceptional dispatch instructions, therefore leaving 20 minutes for RA resources to respond to CAISO dispatch instructions,
- Considers the 10 minute assessment period to be the minimum reasonable assumption for planning purposes,
- Requests that we direct the IOUs to "actively participate in the CAISO's assessment of long-start local capacity resource characteristics" and provide CAISO with relevant data,
- Intends to commit long-start DR resources shown as local RA similar to how it commits and operates other resources and require substitute local RA capacity if available operating hours are consumed,

- Requires pre-contingency dispatch of local RA resources even when weather is not extreme due to outages on transmission lines or other local resources, and
- Recommends that we carefully consider the impacts of long-start, local DR capacity in light of the CAISO's stated pre-contingency dispatch requirements.

Although IEP takes no position on the proposal, it argues that the CAISO's responses "are consistent with three important principles." The principles that IEP identifies are: reliability, consistent resource requirements, and no undue discrimination.

ORA contends that no change should be made for 2017, but suggests that options should be considered to coordinate with the DR program cycle beginning in 2018. ORA recommends that we explore alternatives in order to maintain reliability and avoid discounting current DR programs unnecessarily.

SDG&E and Joint DR Parties contend that CAISO inappropriately conflates planning and operational requirements. CAISO rejects this critique by saying that not to connect the two would be "imprudent, place the CAISO at risk for reliability criteria violations, and jeopardize safe and reliable grid operations."

SDG&E notes that CAISO pre-contingency dispatches long-start thermal units in advance of peak loads, and states its concern that CAISO practices may "overly dispatch" DR. Such over dispatch potentially reduces the reliability effectiveness of the DR and leads to additional ratepayer costs for replacement capacity. Further, SDG&E contends that the question before us is really what DR pre-contingency dispatch characteristics should be required, and offers some factors for consideration of that subject.[21] In reply comments, CAISO notes that it intends to address the question of pre-contingency dispatch characteristics through its 2016-2017 Transmission Planning Process.

SDG&E observes that LCR is based on 1-in-10 loads in combination with an N-1-1 contingency.[22] From this basis, and assuming more DR than currently exists in San Diego, SDG&E calculates that DR resources in San Diego would need to be pre-contingency dispatched day-ahead for between 10 and 50 hours per year. CAISO suggests the exact pre-contingency dispatch requirements may vary between local areas and that this topic requires further study.

PG&E suggests that it is premature to adopt a 20 minute requirement for 2017 and notes that it has expressed strong interest in participating in CAISO studies relevant to DR resources.

SCE neither supports nor opposes the proposal, but recommends that we establish a process to measure the expected performance of DR programs within 20 minutes for those programs with longer response times. SCE contends that some portion of these programs can be relied on for meeting the 20 minute criteria, and proposes that that portion should be counted as local RA. CAISO considers this approach worth further analysis, but does not recommend adoption at this time. NRG supports SCE's suggestion.

Joint DR Parties strenuously oppose CAISO's proposal, arguing that it is discriminatory and unsupported, and that no other ISO/RTO has an analogous rule. Joint DR Parties note that NERC standards do not set individual resource

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[21] See SDG&E Revised Proposals at 6-7.

[22] See 2017 LCR Study at 7-9.

requirements, and claims that CAISO unreasonably uses NERC standards as a basis for its proposal. In support of this assertion, Joint DR Parties also point to other ISOs, which, they allege, do not require response in less than 30 minutes despite having significant reliance on DR.

Joint DR Parties contend that "contingency resources" and "economic resources" are separate services and that requiring both services in a single product may dramatically reduce the number of potential participating customers. They express great concern over changing resource requirements and the idea of multiple resource requirements for a single product.

Joint DR Parties assert that the CAISO proposal is unclear with regard to under what circumstances the 20 minute response time would be required.

CLECA opposes the CAISO proposal for 2017, but suggests that a 30-minute notification time (with exceptions for certain customers) could be acceptable and suggests further study of a 20-minute requirement for future years.

Calpine supports the CAISO's proposal, generally arguing that CAISO's analysis is reasonable and that critiques by other parties are unfounded. Calpine also points to 30 minute dispatch requirements, specific to DR, in other ISO/RTOs. Further, Calpine states that it would view high performance penalties as an adequate substitute for a 20 minute dispatch requirement.

7.1.4. CAISO's Recommendation Will Be Reviewed for Implementation After Stakeholder Process

In order to promote regulatory stability, we decline to make any version of the recommended new rules effective for 2017. We plan, instead, to undertake significant effort, in collaboration with CAISO, DR providers, and other parties, to develop an implementation of this new policy that is consistent with our continued, strong support of DR as a preferred resource. We intend to review the success of this implementation effort following CAISO stakeholder processes and a working group. This process is generally consistent with that described by the CAISO in its May 13, 2016 decision, but we elaborate more detail. Once this process describes an appropriate implementation of this new policy, we intend to adopt a new requirement that any local RA resource must qualify by meeting either of two criteria: the required response time or sufficient energy for pre-contingency dispatch.

As a threshold matter, we agree with the CAISO that local RA resources should be useful to the CAISO in operating the grid reliably, in accordance with applicable standards. As CAISO observes, a fundamental tenet of the RA program has always been to provide resources "when and where needed." No party suggests that the Local RA program should not provide adequate and appropriate resources to the CAISO to meet its uncontested obligation to reposition the system within 30 minutes of a contingency. CAISO's proposal recognizes that there are two distinct ways that resources can support CAISO's efforts to reposition the system: respond in a timely manner on a post-contingency basis or via pre-contingency dispatch. No party has suggested that there is any other viable method for a resource to contribute to CAISO's ability to meet its obligations following a contingency. Therefore, the CAISO's proposed requirement is consistent with the "when and where needed" tenet and ensures that local RA resources are sufficient to manage N-1-1 contingencies during a 1 in-10 load event. Furthermore, we do not find the argument that CAISO "conflates" planning and operational requirements valid. As CAISO notes, sound planning requires consideration of operational needs and reality.

On the other hand, we agree with SCE that the portion of a resource that reliably responds within the required period (even if less than 100%) should be counted for local RA. The CAISO does not contest this conclusion, but its proposal does not include a means of accounting for such resources. We also agree with SDG&E's contention that pre-contingency dispatch requirements are undefined in the CAISO proposal, a fact which is not disputed by CAISO. Taken together, SCE and SDG&E show that we lack critical details concerning the two central paths by which DR resources would comply with the CAISO's proposal. Finally, we agree with parties who argue the details of these matters could unnecessarily diminish DR.

In sum, we support the CAISO's objectives in its proposal, but the proposal lacks critical detail. Further, we wish to avoid instituting unduly narrow or discriminatory restraints on DR through the RA program; instead we want to allow maximum flexibility to DR providers. We find it is necessary to define the implementation details of the CAISO's proposed requirements for local RA resources before new requirements become effective. Therefore, to maximize the benefits of DR resources to local reliability, system reliability, and California energy markets, we request 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. We agree with the May 13, 2016 CAISO decision that a joint CPUC-CAISO workshop is an appropriate and helpful part of this process. The objectives of the stakeholder process and working group should be to: 1) specify the details of each of the two alternative criteria for local RA resources (post-contingency response within a required time period or sufficient energy for pre-contingency dispatch) so that the new requirement can be implemented in an appropriate way, 2) implement any necessary procedures or other changes at the CAISO, and 3) make recommendations for any related changes to the CPUC's RA or other programs.

To develop the clearest rules possible, this CAISO Stakeholder process should include the following tasks:

- Clearly define what "sufficient energy" for pre-contingency dispatch means, including:
    - Quantify how many hours of pre-contingency dispatch should reasonably be required in each local area,
    - Quantify the number of pre-contingency dispatch events that should reasonably be required in each local area,
    - It may be appropriate to define either or both of these requirements (hours, events) by year, season, month,
- Identify a method to ensure that resources are not overly dispatched pre-contingency without good cause,
    - for example, consider whether it is appropriate to develop a new operating procedure for intra-day pre-contingency dispatch of DR resources,
- Clarify operating procedures for post-contingency notification, ensuring equal treatment for all resources,
- Explore mechanisms for a rapid "pre-notification" to provide maximum warning to scheduling coordinators that a post-contingency dispatch is being considered, and
- Identify a method to calculate the portion of a slower responding DR program that can reliably respond within the required period, and therefore be counted for Local RA.

Following a CAISO stakeholder process (or processes) that achieves these tasks, we direct Staff to convene a working group to be comprised of, at a minimum, the CAISO, Staff, the three IOUs, DR providers and others with technical expertise, to 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.

We expect that this working group will convene within one month of CAISO completing a stakeholder initiative dealing with the above issues. We direct the working group to make clear and actionable recommendations for implementation into the RA and DR proceeding. Following these steps, we intend to review this proposal again.

If these requirements are to be effective for 2018, we expect that the CAISO stakeholder process would need to be completed by January, 2017 so that those results could be immediately considered by the working group. In turn, the working group would need to present its recommendations by April 1, 2017. We would then be able to review the working group recommendations and full implementation details in a June, 2017 decision. While we are optimistic that this timeline is feasible, we recognize that it is ambitious. We encourage the parties to work quickly, but without sacrificing quality or due process. If more time is needed to carefully implement these requirements, that time should be taken.

7.2. Use Contract Capacity to Measure RA Capacity of Certain Resources

Energy Division Staff, Joint DR Parties, and SCE each made proposals to use contract capacity to set the RA capacity value (both NQC and EFC) for certain types of DR resources. These DR resources would not be evaluated using the Load Impact Protocols (LIPs). These proposals have many similarities, but differ in certain details including the resource types included and any limitations on the proposal.

Generally, the proposals suggest that penalties under the CAISO tariff and contract provisions are adequate incentive for providers not to overstate the RA capacity that can actually be delivered.

In particular, each of these proposals focus on resources procured through the Demand Response Auction Mechanism (DRAM). DRAM is a competitive procurement framework that has been discussed and approved in R.13-09-011 and pilot programs have been adopted in Resolutions E-4728 and E-4754.

Energy Division Staff propose that all third party (i.e. non-IOU) DR resources should be exempt from the LIPs for RA valuation purposes. SCE proposes that only DRAM resources should be exempt.

Energy Division Staff propose that the exemption from the LIPs should last until the close of the 2019 RA compliance year. Staff note that a time-based limitation avoids pre-judging the size of the DRAM program, which will be addressed in the DR proceeding. Staff states their expectation that by the time this policy would be reevaluated in 2019, the Commission would have the benefit of final results from the 2016 and 2017 DRAM pilots.

SCE proposes that the trial continue as long as the combined size of the DRAM contracts across all IOUs is less than 200 MW.

7.2.1. Alternate Revised Proposal for a "Simplified" Load Impact Protocol

In its revised proposals, SDG&E recommends a streamlined and updated version of the LIPs for supply-side DR resources. SDG&E proposes that DR providers should provide aggregate meter data to the Energy Division for a QC calculation. SDG&E contends that its proposal does not require modification or removal of the LIPs. Instead, SDG&E's proposal is that supply-side DR resources should submit data that satisfies LIPs 4 and 8, and Energy Division would then calculate the monthly QC value according to LIPs 18 and 22.

SDG&E contends that its proposal:

- Is in scope of this proceeding and does not require action in the DR proceeding,
- Avoids what SDG&E sees as a competitive disadvantage on IOU programs compared to third-party programs, and
- Alleviates some of the burden of LIPs on third-party providers as they would only be required to submit data for two LIPs and not perform calculations.

7.2.2. Positions of Other Parties

Many parties recommend that the measurement approach for third party providers should be comparable or the same as for IOU providers. PG&E contends that we should not make changes to the application of the LIPs before undertaking a broader examination of the consequences of treating some providers differently than others. In support of this recommendation, PG&E notes that the 2016 and 2017 DRAM contracts are already exempt from LIPs. SCE does not oppose the Energy Division proposal, but recommends that we observe the market performance of third party providers, re-evaluate the approach, and consider improvements or replacements to LIP studies. SCE notes that even if the LIP requirement were removed for IOU DR, SCE would likely continue to use LIPs to evaluate performance.

Although Joint DR Parties initially made an independent proposal, they "strongly support" Energy Division's revised proposal. SolarCity supports the proposal and further suggests that it should apply to behind the meter storage resources and IOU DR programs. AReM, and ORA support Energy Division's proposal.

Parties also discuss the role of performance incentives, primarily the CAISO's Resource Adequacy Availability Incentive Mechanism (RAAIM) in ensuring that DR resources perform appropriately. SCE notes that CAISO performance incentives should provide the same incentive to any provider, assuming that incentives are passed through to a third party provider.

SDG&E recommends that we direct Energy Division to allocate DRAM II capacity to all customers.

7.2.3. Energy Division's Proposal is Adopted

We adopt Energy Division's revised proposal to use contract capacity for third party DR resources that directly bid in the CAISO market for RA compliance years 2017, 2018, and 2019; these resources will be exempt from use of the LIPs during this period. We do not intend to apply this treatment to DR programs that are managed by third parties but bid into the CAISO market by a utility. However, we agree with many parties that the measurement approach for third party providers should be comparable or the same as for IOU providers. Therefore, during this exemption period, we intend to review whether this exemption should be extended to IOU DR resources or other approaches to measure DR resources in the same manner, regardless of the provider.

We find that substantially all third party DR known to us at this time is already exempt from the LIPs through the end of 2017 due to the DRAM pilot requirements. Therefore, the primary impact of adopting this proposal is extending the duration of the exemption to 2019. While we appreciate the concerns expressed by PG&E and SDG&E about using different measurement techniques, we believe that any competitive disadvantage to IOU DR programs as a result of this temporary exemption is likely to be minimal. Given the scale and experience of the IOU programs in comparison to the characteristics of the third party programs, it is reasonable to use this simpler measurement method at this time for the third party DR that directly bids in the CAISO market. In reaching this conclusion, we rely on the existence of strong performance incentives, through DRAM contracts and RAAIM, to provide a clear incentive for third party resources to perform as promised. As noted above, we will consider extending this approach to IOU DR programs in the future.

Energy Division should allocate DRAM capacity to all customers based on load share, as described in D.15-06-063.[23]

7.3. Evaluating Resources That Are Partially Integrated Into Energy Markets

SCE notes that D.15-11-042 directed the Utilities to only credit RA value to "demand response programs that are integrated into the California Independent System Operator's wholesale market or embedded in the California Energy Commission's unmanaged/base case load forecast."[24] SCE contends that for RA purposes, "integrated program" should be defined as a program that is overall integrated and actively participates in the CAISO market, during periods when it is counted for RA. Importantly, in SCE's definition, not all participating customer service accounts must be registered with the CAISO to meet this definition. One reason that not all customers in a program may be registered as market participants is that some may not meet the size requirements in a specific area (e.g., 100 kW of load drop potential in a sub-load aggregation point). SCE notes that it generally treats all program customers as if they were integrated, regardless of whether or not each account is registered with the CAISO. SCE

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[23] D.15-06-063 at 75.

[24] D.15-11-042, Ordering Paragraph 1.

proposes that for purposes of RA counting, all of the load drop potential in an integrated program should be counted for NQC and/or EFC, using the LIPs.

PG&E supports this proposal for programs using the LIPs, stating that there is no apparent benefit to ignoring non-integrated load drop potential.

CAISO opposes this proposal on the grounds that it is unreasonable and discriminatory.

In D.15-11-042, in response to SCE comments on the PD, we clarified that the portions of a DR program "that are not integrated into the market have no measurable capacity value."[25] We reach the same conclusion today, and decline to adopt SCE's proposal. As noted in D.15-11-042, we have taken several actions to overcome barriers to integration of DR resources and have stated a clear policy direction in favor of integrating DR programs. We decline to create any incentive against that policy by offering RA value to non-integrated load. Therefore, only the integrated portion of a partially integrated program may be counted for RA.

7.4. Two-Hour Maximum Cumulative Capacity (MCC) Bucket

Joint DR Parties propose that we review the existing Maximum Cumulative Capacity (MCC) Bucket system and create a "2-hour bucket." Citing our previous discussion of the changing needs of the grid (e.g., increased need for ramping relative to past focus on peak needs), the Joint DR Parties contend that the time has come to review the MCC buckets. Joint DR Parties believe that a 2-hour bucket would allow greater participation of both DR and storage

[25] D.15-11-042 at 22.

resources in RA markets. Importantly, such a bucket would allow for resources incapable of being dispatchable for at least 4 continuous hours.

Several parties expressed concern about this proposal for a variety of reasons, including NRG, CAISO, and Calpine.

In D.15-06-063, we deferred this idea, but indicated interest in reviewing it again in the future. The analysis necessary to undertake this review, and ultimately support the proposal, has not occurred in Track 1. Therefore, the situation has not materially changed since we deferred this proposal in D.15-06-063, and we must do so again.

We note that one of the key drivers supporting a review of the MCC Bucket system is an increasing focus on grid flexibility. In context of Track 2, Energy Division staff has discussed modifications to the MCC Buckets in the April 5, 2016 workshop. Therefore, it is possible that Track 2 will develop the analysis needed to fully understand the implications of changes to the MCC Buckets. We encourage interested parties to actively participate and collaborate with staff on this issue.

7.5. Demand Response (DR) Combined with Other Resource Types

Joint DR Parties propose that we should allow aggregators to use multiple technologies (e.g., DR, storage, renewables, and EE) to reduce load at a customer site and receive RA credit for the reduction. They propose that the aggregator should be able to establish the load reduction and be held accountable for it. Joint DR Parties further propose to allow the aggregator to determine which method should be used to estimate the baseline against which the load reduction is measured. However, they acknowledge that it may be necessary to consider new baseline methods.

SolarCity supports using contract capacity to measure the capacity of combined resources, noting that such an approach would be simpler than proving the available capacity at each site to the satisfaction of multiple parties.

GPI supports the proposal, stating that "truly combined systems deserve to be treated as a whole."

PG&E opposes this proposal on the grounds that it does not adequately ensure that promised RA support would be delivered.

Calpine expresses concern about the possibility for double-counting, for example of energy efficiency that is included in the load forecast.

While we support the goal of simple mechanisms for establishing RA capacity, we decline to adopt this proposal at this time. It is not clear to us that many or any resources either currently exist or are likely to be constructed soon that would be eligible under this proposal. More importantly, the details of how this proposal would be implemented are unclear. Like PG&E and Calpine, we are concerned that this proposal may lead to double counting (particularly in the case of EE which is usually not integrated into the market as a supply side resource) or otherwise not ensure that promised capacity is delivered. We remain open to a proposal of this type once tools to implement the potentially complicated measurements needed to monitor demand reductions for combined resources are established.

8. Other Proposed Refinements to the Resource Adequacy (RA) Program

Several other proposals for RA refinements are addressed in this chapter.

8.1. Allocation of Flexible Resource Adequacy Requirements

CLECA and PG&E each propose that we should allocate flexible RA requirements to LSEs based on their individual contribution to net load ramp. In

D.15-06-063, we considered and deferred this approach. We noted that this approach would better align costs and cost causation, but chose not to implement for 2016 because of our intent to soon establish a durable flexible product. For 2016, we directed Energy Division to provide informational allocations to LSEs upon their request.

PG&E and CLECA contend that, although it may be necessary to reconsider how to allocate flexible requirements in context of our durable flexible program decision in Track 2, we should implement the proposal for 2017 in the interim. PG&E suggests that we already have all necessary data and that this approach is already employed by the CAISO.

In response to discussion at the workshop, PG&E explains that:

- PG&E does not see a possibility of a new LSE entering the market (and thus needing a flexible requirement allocation) without being able to provide the relevant data to the CAISO,
- The Commission has the authority to require relevant data from LSEs,
- PG&E proposes no change to the treatment of intermittent resources that are economically curtailable, but would support a CAISO effort to address this issue, and
- PG&E proposes no changes to the treatment of either Renewable Energy Credit (REC) or "energy only" resources.

ORA, Calpine, and CalWEA support the proposal based on aligning costs with cost causation. Calpine notes that it would provide efficient incentives for LSEs to reduce their contribution to net load ramp.

AReM recommends that we defer this proposal to Track 2.

SDG&E also recommends that we defer this proposal to Track 2 and further suggests that we should explicitly address economic curtailments. SDG&E is concerned that the CAISO does not receive data from generators in its calculations of contributions to net load ramp, and recommends that we address this issue.

In reply comments, SCPA, City of Lancaster, and MCE (collectively "CCA Parties) support SDG&E's comments and suggest that there is no urgency to adopt this proposal. Further, they contend that this proposal may result in a "punitive" impact on LSEs with larger renewable portfolios and that such an impact works against important California policy goals.

In response to SDG&E, PG&E suggests that we consider SDG&E's ideas as prospective improvements in Track 2 or at another appropriate time in the future.

Again, we defer this issue to Track 2 and its consideration of a durable flexible requirement. We remain open to this proposal, including potential improvements such as the ideas offered by SDG&E in Track 2 or at another point in the future. We encourage Energy Division and parties to consider relevant proposals. For clarity, we note that any proposals need not rely on exactly the CAISO's method or the CAISO's results. Proposals may consider alternative means of achieving the goal of proper alignment of incentives.

Like PG&E and CLECA, we see the goal of aligning costs for flexible RA with cost causation, measured by contribution to net load ramp as a logical approach, but we are not convinced that this proposal achieves its stated goal in practice. We share the concerns of AReM and SDG&E that the proposed approach may not adequately reflect all relevant information. As a result, we fear that this approach may lead to higher levels of free-ridership (i.e. a larger cross-subsidy between LSEs) than the current load ratio share approach.

Nevertheless, we question the CCA Parties' argument that this proposal is counter to California's goals for renewables; we believe the opposite is true. In particular, we note that several of the benefits described by the legislature as justifications for the RPS program are best supported by incentives to minimize renewable integration costs such as additional flexibility needs.[26] This policy provides an incentive to minimize flexibility needs and is consistent with the goals of the RPS statutes.

8.2. Continuing Bundling of Effective Flexible Capacity (EFC) and Net Qualifying Capacity (NQC)

CLECA, Joint DR Parties, and Shell all offer proposals to unbundle EFC from NQC. Each of these parties contends that the current requirement that a resource have an NQC in order to have an EFC inappropriately and unnecessarily constrains the pool of resources able to provide flexibility services (i.e. have an EFC). These parties argue that the attributes needed to provide EFC are materially distinct from those needed to provide NQC. A key example is that the Must Offer Obligation hours are different for EFC and NQC. Therefore, they suggest that resources should be eligible to sell either EFC or NQC without necessarily selling the other product. They argue that unbundling these products will reduce costs to ratepayers. Shell makes the proposal in the most general form suggesting that all resources should be unbundled, while CLECA and Joint DR Parties focus on DR and storage. CESA supports these proposals.

AReM opposes this proposal, noting that the implications are potentially complex. Importantly, AReM points to Cost Allocation Mechanism (CAM) resource allocations as a potential challenge with this approach.

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[26] See: §399.11 (b), in particular benefits (1) and (6)-(8).

NRG opposes the proposal, arguing that there is no material societal benefit until the incremental value of EFC capacity grows to be significant.

We will again defer this issue until Track 2 or a later time. This issue is naturally connected to our consideration of a durable flexible capacity product in Track 2. We encourage parties in Track 2 to present more detailed proposals on this subject, addressing implementation details such as how CAM resources should be allocated and controls to avoid double counting.

8.3. Load Forecasting

Load forecasting is a fundamental requirement of the RA program and we have addressed the subject in many decisions. D.04-10-035 and D.05-10-042 established that LSEs would submit load forecasts, and that the CEC would make certain adjustments to those forecasts for RA purposes. In D.12-06-025, we changed from using an "average" coincident adjustment to an "LSE specific" coincident adjustment.[27]

In Phase 1 of this proceeding, parties expressed certain concerns about the load forecasting process, generally focused on transparency and consistency. As a result, we directed the Energy Division, in consultation with CEC, to publish: 1) dates and times of system peak for coincident adjustments, 2) a step-by-step process for adjustment, and 3) a detailed explanation of any discretionary adjustments. Further, we directed the CEC to "apply the same adjustment factors and formulas to all LSEs equally and consistently." Lastly, we directed

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[27] D.12-06-025, Ordering Paragraph 4.

staff to hold a workshop on coincident adjustments and consider how a "forecast approach" could work in the future.[28]

Energy Division posted a report to its website in October 2015 and held workshops on February 18, 2016 and March 25, 2016.

In response to workshop discussion, Energy Division posted an additional report to its website on May 12, 2016, shortly before the proposed decision in this proceeding was issued. Due to the timing of the publication, parties were not able to comment on the report prior to the proposed decision.

8.3.1. Positions of Parties

CLECA recommends that: 1) only one peak should be used per calendar month, 2) CEC should use non-weather-normalized peak load data, and 3) Energy Division should host an additional in-person full-day workshop to review other ISOs' load forecasting methods by mid-November. CLECA contends that using the median of multiple peaks inappropriately lowers the coincidence of temperature sensitive loads and is therefore inconsistent with cost causation. CLECA suggests that weather-normalization leads to misallocations of RA requirements, and is not used in coincidence factor adjustments by other ISOs. For clarity, CLECA supports continued reliance on weather normalization to set total RA requirements, but distinguishes this use from coincidence adjustments. In summary, CLECA argues that the process for allocating RA requirements should be aligned with cost-causation, use clear and available data, and only be adjusted in limited, known ways.

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[28] D.15-06-063 at 41.

Shell recommends that: 1) Energy Division and the CEC should post load data within seven days of receiving the data from the CAISO and clearly identify the data source, 2) Energy Division should clarify how it shares results of coincidence adjustments with LSEs, 3) Energy Division should use the most recent year of load data, 4) CEC should use non-weather-normalized peak load data for coincidence adjustments, and 5) Energy Division should provide RA obligations to LSEs no later than June 1.

DACC summarizes the steps that Energy Division and CEC have taken since D.15-06-063 to provide more information about the load forecast process, concludes that these steps are insufficient and that "progress towards increased transparency and consistency continues to lag." DACC notes that little workshop discussion addressed changing from "historic" to "forecast" approach or methods in other jurisdictions, as we suggested in D.15-06-063. The continuing concerns that DACC expresses are 1) using more years of data may dampen peaks and may not reflect changing grid conditions, 2) variation in the number of peaks used among LSEs may not lead to standardized or fair treatment of different LSEs, and 3) weather normalization should be applied for forecasts, but not for historical peaks for coincidence adjustments. DACC contends that other ISOs handle these issues differently. DACC concludes that Energy Division and CEC have not adequately supported the current approach, and that the discussion of these issues to date does not meet the goals of D.15-06-063. Therefore, DACC recommends that we direct Energy Division to host "multi-day, in person workshops" with emphasis on best practices from other regions and to produce a report by the end of 2016 with a "consensus approach" on improvements for RA compliance year 2018.

ORA recommends that we provide a forum for continued discussion of this subject and "foster greater stakeholder involvement."

SDG&E contends that coincidence adjustments should account for the increasing penetration of distributed solar generation. Behind-the-meter solar is pushing the time of coincident peak later in the day. SDG&E recommends that estimates of historical behind-the-meter solar generation should be considered, along with CEC forecasts of solar generation, to account for future changes in coincidence and peak load levels.

8.3.2. Discussion

We agree with ORA and other parties that this subject merits continued discussion between Staff and parties. We note that the document posted by the Energy Division on May 12, 2016 addresses many of the questions and topics of concern raised by stakeholders. However, parties have not yet commented on that document. As described below, we direct Energy Division to devote additional workshop time to explaining this document and gathering party comments.

Consistency and accuracy are important goals for load forecasting for RA purposes. We recognize that there may be some tension between these goals. Transparency is critical to resolving this tension fairly. Energy Division and the CEC have made significant progress toward the transparent application of their load forecasting process.

One particular area of concern addressed by multiple parties is the use of the median peak event to develop coincident factors. Parties correctly note that the median may benefit weather-sensitive LSEs. However, in our view, the median is appropriate to represent the central tendency of the peak load data. It is reasonable to base coincidence factors on a midpoint of the data, not extremities like maximum. Using a single peak event (i.e., the maximum) may create an opportunity for LSEs with high degrees of control over their load to substantially avoid RA obligations. The fact that other jurisdictions reach different conclusions on this point is not directly relevant, it merely demonstrates different evaluations of the cost responsibility for a single peak versus a typical peak event.

Another concern expressed by multiple parties is the use of weather normalized data. The document published by Energy Division on May 12, 2016 appears to address this concern. However, parties are free to raise this issue in the process described below, if necessary.

We agree with Shell that LSEs should receive their final load forecasts for RA purposes with adequate time for procurement. However, we decline to set a firm deadline of June 1 as suggested by Shell. Instead, we set a goal of July 1 for Energy Division to issue final load forecasts.

In order to continue to advance our goals of accuracy, consistency, and transparency, we authorize Energy Division to:

1. Re-issue its May 12, 2016 document as a proposal for RA compliance year 2018 by September 1, 2016. Energy Division may make changes to the document, consistent with our goals, before issuing this proposal.

2. Hold at least one full-day, in person workshop to discuss this proposal by November 1, 2016. Provide an opportunity during the workshop for any party who wishes to present proposed changes to the staff proposal to do so. Energy Division and/or the assigned Administrative Law Judge (ALJ) may set a deadline for parties to make proposed changes in advance. Energy Division may revise its proposal following the workshop, according to a schedule developed by the ALJ.

8.4. Posting of Effective Flexible Capacity (EFC) and Net Qualifying Capacity (NQC) Lists

SDG&E proposes that final NQC and EFC lists should be posted by August 1st of each year. SDG&E suggests that this would give transacting parties adequate time to procure capacity to meet year-ahead requirements. SDG&E submits that this proposal is consistent with our goal of 90 days between final RA requirements and year-ahead showings. Over- or under-procurement due to uncertainty can lead to increased ratepayer costs. SDG&E suggests the following schedule:

Compliance Month	Posting Date for Existing Resources	Posting Date for New Resources
Year Ahead (end of Oct)	August 1	October 12
Month Ahead (January)	September 1	November 12
Month Ahead (February)	October 1	December 12
Month Ahead (March)	November 1	January 12

ORA and AReM support this proposal. PG&E supports the proposal, if the Commission and CAISO agree that it is realistic. No party opposes this proposal.

We recognize that Energy Division faces a variety of potential complications in posting these lists. These challenges may vary year to year and may not always be visible to other stakeholders. Therefore, we decline to adopt this proposal outright. Nevertheless, we agree with SDG&E that there is a clear benefit to timely availability of procurement related information. Accordingly, we adopt SDG&E's proposed timeline as a goal for Energy Division. Staff should publish the final lists as early as reasonably feasible each year, and should aspire to do so no later than August 1.

8.5. Changes to Pre-Dispatch Resources

PG&E proposes to changes to our recently adopted policy for "pre-dispatch" resources. Note that in this context, the term "pre-dispatch" is used differently than discussed in Section 9.1. D.15-06-063 adopted a pre-dispatch definition enabling facilities that are able to submit a schedule into the day ahead market, but are not available for re-dispatch in the real time market, to receive a QC value based on their scheduled MW amounts in the day ahead market. Only qualifying facility (QF) cogeneration facilities are currently eligible for the "pre-dispatch" designation.

PG&E believes that the adopted policy is flawed because it focuses on the MW quantity that the CAISO schedules, rather than what the resource bids or self-schedules into the market. Thus, PG&E proposes that the policy should be revised so that the QC for a pre-dispatch resource is based on the MW amount the resource has bid or self-scheduled into the CAISO day-ahead market since that is the amount that establishes the capacity that the resource is making available to the grid. While the CAISO may actually schedule a portion or none of that capacity, the full amount offered to the market is available for dispatch. Because the costs of pre-dispatch resources that do not clear the day-ahead market tend to be high, PG&E argues that using the MW scheduled approach is very likely to underestimate the amount of capacity being made available to the day-ahead market.

Additionally, PG&E proposes expanding the resource types eligible for the pre-dispatch designation to include biomass and biogas facilities and cogeneration facilities that are not qualifying facilities.

TURN, GPI, and SDG&E support PG&E's proposals.

GPI focuses on extending the pre-dispatch category to include biomass and biogas facilities. GPI also supports using the amount of power bid, not the amount scheduled since the difference is a matter of economics, not physical generating capacity to support the grid.

SDG&E supports PG&E's proposal to use bid amounts rather than scheduled amounts, and notes that our exact intent may have been ambiguous in D.15-06-063. SDG&E also supports adding non-QF cogeneration facilities.

No party opposes PG&E's proposals and we find them reasonable, marginal improvements relative to the status quo. Logically, the QC should be set based on the capability of the resource. Either Pmax or quantity available in the market, whether bid or self-scheduled, indicates the capability, not the amount that clears the market. Further, we see no compelling reason that this treatment should not be extended to the broader categories of resources that PG&E suggests. Therefore, we modify our policy so that all biomas, biogas, and cogeneration facilities, regardless of QF status, that are able to submit a schedule into the day-ahead market, but are not dispatchable, may receive a QC value based on the higher of their bid or self-scheduled amounts in the day-ahead market. This policy promotes efficient, market-based economic dispatch by removing a disincentive for these resources to bid economically. We clarify that to the extent that an individual resource is dispatchable, it may continue to apply for a QC value based on its Pmax.

Energy Division is authorized to attempt to obtain appropriate bid and self-schedule data and to implement this QC calculation. In the event that not all bid data are available or the calculation is otherwise infeasible, Energy Division may adapt this calculation as needed, including by using settlement data as a supplement.

We note that this pre-dispatch policy requires considerably more work for the Energy Division than PG&E's original, Phase 1 proposal to use Pmax. From our experience to date, the benefits of this difference are not clear. We remain open to future proposals to use Pmax for these resources.

9. Comments on Proposed Decision

The proposed decision of Administrative Law Judge Dudney in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on June 9, 2016, and reply comments were filed on June 14, 2016 by Calpine, CAISO, CCA Parties, Clean Coalition, CLECA, GPI, Joint DR Parties, ORA, PG&E, SDG&E, and TURN. The proposed decision was modified to account for comments and non-substantive changes were made to improve clarity.

10. Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and Kevin Dudney is the assigned ALJ in this proceeding.

Findings of Fact

1. The assumptions, processes, and criteria used for the CAISO's 2017 LCR Study were discussed and recommended in a CAISO stakeholder meeting, and they generally mirror those used in the 2007 through 2016 LCR studies.
2. In previous RA decisions, the Commission delegated ministerial aspects of program administration to the Energy Division.
3. Tracking changes in local RA procurement costs resulting from the shift in local RA obligations from LA Basin to the San Diego sub-area attributable to operational concerns at the Aliso Canyon storage facility may inform future Commission decisions.

4. It is appropriate to continue the flexible capacity program established by D.13-06-024.

5. The CAISO's 2017 FCR Study calculated flexible capacity needs for 2017 based on the method adopted in D.13-06-024.

6. Energy Division used a commercially available model to estimate the ELCC of wind and solar resources. Many parties are generally supportive of Energy Division's modeling efforts and note that the collaborative process led by Energy Division has made significant progress.

7. Significant outstanding questions remain about the ELCC modeling efforts. It is likely that continued, collaborative efforts of Energy Division and parties will overcome these challenges in time for adoption of ELCC for 2018. We intend to adopt ELCC for compliance year 2018, if these challenges are overcome.

8. It is necessary to define the implementation details of the CAISO's proposed requirements for local RA resources before new requirements become effective.

9. The appropriate and non-discriminatory implementation of proposed new requirements for local RA resources will take considerable, collaborative effort of CAISO, DR providers, IOUs, other parties, and Energy Division staff. This effort is necessary to balance our reliability goals with our continuing support for preferred resources and fair, transparent market rules.

10. Substantially all third party DR known to us at this time is already exempt from the LIPs through the end of 2017 due to the DRAM pilot requirements.

11. Any competitive disadvantage to IOU DR programs as a result of a temporary exemption for third party DR programs from LIPs is likely to be minimal.

12. Strong performance incentives, including DRAM contracts and RAAIM, provide a clear incentive for third party DR resources that directly bid in the CAISO market to perform as promised.

13. It is reasonable to use the simpler measurement method of contract capacity at this time for the third party DR resources that directly bid in the CAISO market.

14. As noted in D.15-11-042, we have taken several actions to overcome barriers to integration of DR resources and have stated a clear policy direction in favor of integrating DR programs.

15. Offering RA value to non-integrated load would create an incentive counter to our policy of integrating DR programs.

16. Analysis necessary to undertake a review of two hour MCC buckets has not occurred in Track 1.

17. The proposed approach of allocating flexible RA requirements by contribution to net load ramp may lead to higher levels of free-ridership than the current load ratio share approach.

18. There are potential efficiency gains from unbundling flexible capacity from system capacity, but there remains significant uncertainty and potential for negative impacts.

19. Accuracy, transparency, and consistency are important goals of the load forecast adjustment process.

20. The median is appropriate to represent the central tendency of peak load data.

21. There is a clear benefit to timely availability of procurement related information, and it is reasonable to establish a goal for Energy Division to publish load forecasts by July 1st and the NQC list by August 1st of each year.

22. Logically, the QC should be set based on the capability of a pre-dispatch resource, as indicated by either Pmax or quantity available in the market.

Conclusions of Law

1. The CAISO's 2017 LCR Study results are a reasonable basis for establishing local procurement obligations for 2017 applicable to Commission-jurisdictional LSEs.

2. It is reasonable to require SDG&E and SCE to file and serve Tier 2 advice letters establishing appropriate mechanisms to track changes in local RA costs resulting from the shift in local RA obligations from LA Basin to the San Diego sub-area attributable to operational concerns at the Aliso Canyon storage facility. These Tier 2 Advice Letters should be filed within 30 days of the effective date of this decision.

3. The CAISO's 2017 FCR Study results are a reasonable basis for establishing flexible procurement obligations for 2017 applicable to Commission-jurisdictional LSEs.

4. Energy Division should implement the RA program for 2017 in accordance with the adopted policies in this and previous decisions.

5. In order to promote due process to all parties, the CAISO should adhere to the following guidelines for future LCR and FCR studies:

   a) All draft studies should be posted to the CAISO website when they are released,

   b) Posted drafts should remain publically accessible for the duration of the process,

c) All comments on draft studies should be posted to the CAISO website soon after they are received,

d) If necessary due to confidentiality concerns, commenting stakeholders should be encouraged to submit public and confidential versions of their comments,

e) Draft and final studies should describe and address the impact of any data that was not available to the CAISO to perform the study,

f) Work papers supporting the final studies should be shared with Energy Division staff as necessary to implement the RA program,

g) The final studies should include a response to comments,

h) The final studies should be filed and served in the then-current RA proceeding by April 15 of each year, unless otherwise scheduled by the ALJ or scoping memo, and

i) The final LCR study should include an explanation of the role of DR, including busbar level data provided by the utilities.

6. It is reasonable to defer adoption of ELCC until outstanding questions are resolved.

7. The local RA program should provide adequate and appropriate resources to the CAISO to meet its uncontested obligation to reposition the system within 30 minutes of a contingency.

8. It is reasonable to review the success of the implementation efforts associated with the proposed requirement for local RA resources in a future RA decision. This review will ensure that, as implemented, the requirements appropriate and non-discriminatory.

9. The portion of a resource that reliably responds within the required response time (even if less than 100%) should be counted for local RA. A method to implement this possibility should be developed.

10. The CAISO should use open and transparent stakeholder processes to develop clear rules to implement the new requirement for local RA resources. These processes should include the tasks identified in Section 7.1.4 of this decision.

11. Following the completion of the CAISO stakeholder processes identified in the previous Conclusion of Law, staff should convene a working group to be comprised of, at a minimum, the CAISO, Staff, the three IOUs, DR providers and other with technical expertise, to develop clear recommendations to the Commission on implementation details.

12. Energy Division's revised proposal to use contract capacity for third party DR resources that directly bid in the CAISO market for RA compliance years 2017, 2018, and 2019 should be adopted.

13. Unbundling flexible capacity from system capacity should be deferred and taken up in conjunction with consideration of a more durable flexible product.

14. Energy Division should:

   a. Re-issue its May 12, 2016 document as a proposal for RA compliance year 2018 by September 1, 2016. Energy Division may make changes to the document, consistent with our goals, before issuing this proposal.

   b. Hold at least one full-day, in person workshop to discuss this proposal by November 1, 2016. Provide an opportunity during the workshop for any party who wishes to present proposed changes to the staff proposal to do so. Energy Division and/or the assigned ALJ may set a deadline for parties to make proposed changes in advance. Energy Division may revise its proposal following the workshop, according to a schedule developed by the ALJ.

15. All biomass, biogas, and cogeneration facilities, regardless of QF status, that are able to submit a schedule into the day-ahead market, but are not

dispatchable should be eligible to receive a QC value based on the higher of their bid or self-scheduled amounts in the day-ahead market.

O R D E R

IT IS ORDERED that:

1. The "Option 2/Category C" Local Capacity Requirements set forth in the California Independent System Operator's 2017 Local Capacity Technical Analysis Final Report and Study Results, filed April 29, 2016, are adopted as the basis for establishing local resource adequacy procurement obligations for Commission-jurisdictional Load Serving Entities as defined by Public Utilities Code Section 380(j). The Local Capacity Requirements for 2016 are as follows:

Local Area Name	Existing Capacity Needed	Deficiency	Total (MW)
Humboldt	157	0	157
North Coast / North Bay	721	0	721
Sierra	1731	312	2043
Stockton	402	343	745
Greater Bay	5385	232	5617
Greater Fresno	1760	19	1779
Kern	492	0	492
LA Basin	7368	0	7368
Big Creek/ Ventura	2057	0	2057
San Diego/ Imperial Valley	3570	0	3570
Total	23643	906	24549

2. The local resource adequacy program and associated requirements adopted in Decision (D.) 06-06-064 for compliance year 2007, and continued in effect by subsequent decisions, including most recently D.15-06-063, are

continued in effect for compliance year 2017, subject to the modifications, refinements, and local capacity requirements adopted in ordering paragraphs in this decision.

3. San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) shall file and serve Tier 2 advice letters establishing appropriate mechanisms to track changes in Local Resource Adequacy procurement costs resulting from the shift in Local Resource Adequacy obligations from the LA Basin local area to the San Diego sub-area attributable to the operational concerns at the Aliso Canyon storage facility. If practical, SDG&E and SCE are encouraged to coordinate their tracking mechanisms to aid our review of these cost changes. These Tier 2 Advice Letters shall be filed within 30 days of the effective date of this decision.

4. The California Independent System Operator's Final 2017 Flexible Capacity Needs Assessment, filed April 29, 2016, is adopted as the basis for establishing flexible procurement obligations for 2017 applicable to Commission-jurisdictional Load Serving Entities as defined by Public Utilities Code Section 380(j), consistent with the flexible capacity framework adopted in Decision 13-06-024. The Flexible Capacity Requirements for 2017 are as follows:

NOTE: All numbers are in Megawatts	Total Flexible Requirement	Category 1 (minimum)	Category 2 (100% less Cat. 1 & 3)	Category 3 (maximum)
January	13,281	6,687	5,930	664
February	12,238	6,162	5,464	612
March	12,918	6,504	5,768	646
April	11,764	5,923	5,253	588
May	11,600	7,462	3,558	580
June	10,290	6,619	3,156	515
July	9,366	6,025	2,873	468
August	9,292	5,977	2,850	465
September	10,501	6,755	3,221	525
October	10,761	5,418	4,805	538
November	14,425	7,263	6,441	721
December	14,276	7,188	6,374	714

5. The Commissions Resource Adequacy program is modified as follows:

   a. Energy Division's revised proposal to use contract capacity for third party Demand Response resources that directly bid in the market of the California Independent System Operator for Resource Adequacy compliance years 2017, 2018, and 2019 is adopted. These resources are exempt from the use of Load Impact Protocols to establish capacity for this period; contract capacity will be used instead.

   b. All biomass, biogas, and cogeneration facilities, regardless of qualifying facility status, that are able to submit a schedule into the day-ahead market, but are not dispatchable may receive a qualifying capacity value based on the higher of their bid or self-scheduled amounts in the day-ahead market.

6. Following an appropriate California Independent System Operator stakeholder process, Energy Division shall convene a working group to be comprised of, at a minimum, the California Independent System Operator, the three Investor Owned Utilities, Demand Response providers and other parties

with technical expertise, to develop clear recommendations to the Commission on the following:

a. Necessary program tariff and contract modifications and/or new provisions to enable pre-dispatch of Local Resource Adequacy resources,

b. Contract provisions related to the minimum required number of pre-dispatches per year, based on the California Independent System Operator estimates of total pre-dispatch need in each local area,

c. Any other modifications to policy or rules necessary to ensure that Demand Response resources can qualify as local Resource Adequacy, based on a non-discriminatory application of those rules.

7. Energy Division is authorized to:

a. Re-issue its May 12, 2016 load forecasting document as a proposal for Resource Adequacy compliance year 2018 by September 1, 2016, including any changes, consistent with our goals.

b. Hold at least one full-day, in person workshop to discuss this proposal by November 1, 2016. Provide an opportunity during the workshop for any party who wishes to present proposed changes to the staff proposal to do so. Energy Division and/or the assigned Administrative Law Judge (ALJ) may set a deadline for parties to make proposed changes in advance. Energy Division may revise its proposal following the workshop, according to a schedule developed by the ALJ.

8. Energy Division is authorized to attempt to obtain appropriate bid and self-schedule data and to implement the Qualifying Capacity calculation for pre-dispatch resources. In the event that not all bid data is available or the calculation is otherwise infeasible, Energy Division may adapt this calculation as needed, including by using settlement data as a supplement.

9. Rulemaking 14-10-010 remains open.

This order is effective today.

Dated June 23, 2016, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
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