STATE OF CALIFORNIA EDMUND G. BROWN JR., Governor

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

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November 21, 2018 **Agenda ID #17045**
**Ratesetting**

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

This is the proposed decision of Administrative Law Judges Chiv and Allen. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's January 10, 2019 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

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

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

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

AES:avs
Attachment

Decision **PROPOSED DECISION OF ALJ CHIV AND ALJ ALLEN**
**(Mailed 11/21/2018)**

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

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

# DECISION REFINING THE RESOURCE ADEQUACY PROGRAM

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## DECISION REFINING THE RESOURCE ADEQUACY PROGRAM

### Summary

This decision adopts changes to the Resource Adequacy program, including identifying the distribution utilities as the central procurement entity for their respective distribution service areas and adopting specifications and requirements for implementation of multi-year local procurement to begin for the 2020 compliance year.

This proceeding remains open.

### 1. Background

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

In June 2018, the Commission issued Decision (D.) 18-06-030, which adopted local capacity obligations for 2019 and resolved certain issues in Track 1 of this proceeding. The Commission also issued D.18-06-031 in June 2018, which adopted flexible capacity obligations for 2019. D.18-06-030 (referred to as the Track 1 decision), as well as the Order Instituting Rulemaking for this proceeding, provides additional information on the procedural and substantive background of this proceeding.

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

A Scoping Memo and Ruling (Scoping Memo) for this proceeding was issued on January 18, 2018. The Scoping Memo identified the issues to be addressed in the proceeding and set forth a schedule and process for addressing those issues. The Scoping Memo organized the various issues into three tracks (Track 1, Track 2 and Track 3). In general, Track 2 issues are further refinements to the Commission's Resource Adequacy program, some of which are guided by directives adopted in the Track 1 decision. As the Track 1 decision adopted a general multi-year and central procurement framework for local RA, the primary issues in Track 2 involve determining the implementation requirements for multi-year and central procurement of local RA capacity.

Parties served Track 2 opening testimony on July 10, 2018. The parties who submitted testimony were Alliance for Retail Energy Markets (AReM); California Community Choice Association (CalCCA); California Energy Storage Alliance (CESA); California Independent System Operator (CAISO); Calpine Corporation (Calpine); Center for Energy Efficiency and Renewable Technologies (CEERT); CPower, EnerNOC, Inc. (EnerNOC)[2] and EnergyHub (collectively, the Joint DR Parties); EnerNOC; Green Power Institute (GPI); Independent Energy Producers Association (IEP); Middle River Power, LLC (Middle River); NRG Energy, Inc. (NRG); OhmConnect, Inc. (OhmConnect); Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E); Shell Energy North America (US), L.P. (Shell); Sierra Club, California Environmental Justice Alliance (CEJA), and Union of Concerned Scientists (UCS) (collectively, the Joint Environmental Parties); Southern California Edison Company (SCE); the Utility

[2] On October 24, 2018, EnerNOC notified the Commission that its name had changed to Enel X North America, Inc. (Enel X). Because the pleadings in this case were primarily filed under the former name EnerNOC, we will refer to this party as EnerNOC in this decision.

Reform Network (TURN); and Western Power Trading Forum (WPTF). The Supply Side Working Group (SSWG) submitted a proposal in the form of comments on July 10, 2018. The Commission's Energy Division (Energy Division) served its Track 2 proposals on July 12, 2018. The Administrative Law Judge's e-mail ruling, dated November 16, 2018, that filed and served Energy Division's proposals is affirmed.

A workshop on the multi-year forward procurement and central buyer proposals was held on July 19, 2018. A workshop on the 2019 RA templates and guides was held on August 2, 2018. A Prehearing Conference (PHC) was held on August 1, 2018.

Comments to parties' opening testimony, in lieu of reply testimony, were served and filed on August 8, 2018. Comments were received from AReM; CalCCA; CEERT; CESA; CAISO; California Large Energy Consumers Association (CLECA); California Wind Energy Association (CalWEA); Calpine; EnerNOC; GPI; IEP; the Joint DR Parties; the Joint Environmental Parties; Large-scale Solar Association (LSA); LS Power Development, LLC (LS Power); Middle River; NRG; Office of Ratepayer Advocates (ORA)[3]; PG&E; SDG&E; Sentinel Energy Center, LLC (Sentinel) and Diamond Generating Corporation (Diamond) (collectively, Sentinel/Diamond); Shell; Sunrun Inc. (Sunrun); TURN; and WPTF.

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[3] Senate Bill 854 (Stats. 2018, ch. 51) amended Public Utilities (Pub. Util.) Code § 309.5(a) to state that the Office of Ratepayer Advocates is now named the Public Advocate's Office of the Public Utilities Commission. Because the pleadings in this case were primarily filed under the name Office of Ratepayers Advocates, we will refer to this party as ORA in this decision.

Reply comments were served and filed on September 14, 2018. Parties who submitted reply comments were CAISO, CalCCA, Calpine, CEERT, the Joint Environmental Parties, PG&E, SCE, and SDG&E.

On October 5, 2018, the Administrative Law Judges (ALJ) requested additional comments on SCE's central procurement proposal. Comments were submitted on October 16, 2018 by AReM, CalCCA, CLECA, Calpine, GPI, the Joint Environmental Parties, NRG, ORA, PG&E, SDG&E, Shell, TURN, and WPTF. On October 24, 2018, CalCCA, CLECA, Calpine, GPI, the Joint Environmental Parties, PG&E, and SCE submitted reply comments.

## 2. Issues Before The Commission

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

(1) Adopting multi-year local RA program requirements (if such framework was adopted in Track 1).

(2) Refinements to Local Area Rules, as time permits. Further refinements in this category can include:

   (a) adjusted or waived LSE procurement obligations for certain local areas with resource deficiencies or near-term procurement difficulties;

   (b) modified treatment of specific local areas or sub-areas (such as San Diego), and associated cost allocation;

   (c) seasonally varying Local Capacity Requirements (LCRs);

   (d) local penalty waiver requirements; and

   (e) increased transparency for the Commission, and for LSEs procuring RA, regarding which resources are essential for local and sub-area reliability.

(3) Refinements to the RA program. Further refinements in this category can include:

(a) Flexible RA rule revisions to address ramping over shorter intervals and better allow for participation of renewables and out-of-state resources such as hydropower in Washington and Oregon;

(b) refinements to production cost modeling algorithms and further integration of modeling-based concepts into RA program rules and other RA waiver and penalty rules; and

(c) other issues identified by Energy Division or by parties in proposals. (Scoping Memo at 7-8.)

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

## 3. Discussion

### 3.1. Multi-Year Ahead Procurement and Central Procurement Entity

The Track 1 decision discussed the substantive history of the Commission's consideration of a multi-year ahead procurement framework. (D.18-06-030 at 24.) In the Track 1 decision, the Commission concluded that there "is value to having a multi-year local RA requirement to ensure that resources needed for reliability are procured in an orderly fashion, and the Commission intends to implement a multi-year local RA requirement in Track 2 of this proceeding." (*Id.*) The Commission did not adopt multi-year requirements for flexible and system RA, although we stated that this may be considered at a future date.

The Track 1 decision also discussed and analyzed whether central procurement or LSE-based procurement was most appropriate for a multi-year local RA program. The Commission concluded that a central procurement system, at least for some parts of the local RA requirement, was "most likely to provide cost efficiency, market certainty, reliability, administrative efficiency, and customer protection." (*Id*. at 30.)

As the foundation for a multi-year and central procurement framework was set forth in the Track 1 decision, the specifications and implementation details of this framework were not adopted and will be adopted in this decision so that implementation can begin for the 2020 RA compliance year. First establishing the identity of the central procurement entity and the scope of central procurement (full versus residual procurement) are critical pillars to adopting further implementation directives. Thus, we begin by addressing these fundamental issues.[4]

The Commission recognizes that as this is the initial implementation of a multi-year local program, there may be a need for further refinement in the near future. We intend to continue to monitor and evaluate the multi-year local procurement process, as well as the central procurement function, and may refine the requirements adopted herein in future years.

#### 3.1.1. Central Procurement Entity

In the Track 1 decision, the Commission directed parties in Track 2 to propose central buyer structures that include a single central buyer or a single central buyer per Transmission Access Charge (TAC) area, and to address the ability of the central buyer to procure all available resource attributes (*e.g.*, flexible RA) and not just local RA requirements. The Commission did not

[4] Because parties' proposals contain interrelated components, to the extent that the Commission adopts a requirement in this decision that differs from a party's recommendation, we nevertheless consider the remaining aspects of a proposal, rather than disregard it in its entirety.

foreclose the possibility of more than one central buyer per TAC area but stated it was not convinced of the feasibility of that solution. For proposals offering a two-buyer per TAC area solution, the Commission stated that the proposal should be "concrete and implementable, and: 1) address equitable allocation of costs to all customers, and 2) ensure cost-effective, efficient and coordinated procurement for each local and sub-local area within the TAC." The Commission added that all central buyer proposals must address balancing "economic procurement criteria with other essential state policies, such as greenhouse gas emissions reductions targets and consideration of impacts on disadvantaged communities." (D.18-06-030 at 33.)

As a preliminary matter, the Commission finds broad support among parties for a central buyer structure for at least some portion of local RA procurement.[5] A few parties oppose the central buyer structure in favor of a central capacity market approach[6] or expansion of the CAISO's backstop authority.[7] In light of parties' broad support for a central buyer structure, as well as the Track 1 decision's discussion in favor of a central procurement entity, the Commission adopts this structure and proceeds with designating the appropriate entity to serve as the central buyer.

Proposals for a central procurement entity generally fall into three categories: (1) the distribution utilities, (2) a special purpose entity, and (3) the CAISO.

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[5] *See, e.g.,* proposals from the CAISO, Calpine, CLECA, Energy Division, GPI, IEP, the Joint Environmental Parties, the Joint DR Parties, Middle River, NRG, PG&E, SCE, SDG&E, TURN.

[6] *See, e.g.*, proposals from AReM, Shell, WPTF.

[7] *See, e.g.*, proposal from CalCCA.

#### 3.1.1.1 Distribution Utilities

Energy Division and several parties, including CLECA, CEERT, and TURN, support having the distribution utilities (that is, the investor-owned electric utilities) serve as the central procurement entities for their respective distribution areas.[8] Some favor the distribution utilities serving as central buyers but only on an interim basis.[9] ORA recommends the distribution utilities serve as central buyers but with an independent consultant hired to administer solicitations and select contracts. (ORA Comments at 14.) SCE supports the distribution utilities as central buyers provided certain conditions are met, such as durable cost recovery and equitable cost allocation, and only on an interim basis. (SCE Testimony at 17.)

Energy Division proposes that the distribution utilities serve as central buyers for their TAC area but that mitigation measures be adopted to address anti-competitive and transparency concerns. Such measures may include creation of an independent procurement arm, oversight by a stakeholder monitoring committee, application of competitive neutrality rules, and retention of an independent evaluator to observe solicitations and transactions. (Energy Division Proposal at 15.)

Those who oppose designation of the distribution utilities raise several concerns. Some argue that the utilities cannot be neutral buyers, as they could potentially favor their own resources over third-party resources or select solutions that expand their rate base, such as new transmission or utility-owned

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[8] *See* CEERT Testimony at 4, CLECA Comments at 5, Energy Division Proposal at 15, TURN Comments at 3.

[9] *See, e.g.*, CLECA Comments at 5.

storage.[10] Some Community Choice Aggregation (CCA) and Electric Service Provider (ESP) parties are broadly concerned with having utilities procure on their behalf, while others note the lack transparency inherent in utility procurement.[11] Some find it problematic to designate a central buyer who, based on various estimates, will eventually provide generation to a minority of customers as a result of increasing load migration to CCAs and growth in distributed energy resources, such as rooftop solar.[12]

Lastly, the distribution utilities express concern with the potential financial costs and risks associated with the central procurement function, particularly in light of inverse condemnation risk.[13] The utilities are concerned that the increased financial commitment associated with large-scale procurement could raise debt equivalency issues. Debt equivalence applied to a utility's balance sheet, as SDG&E contends, without corresponding increase in equity or compensation could negatively impact the utility's credit standing and financial stability. (SDG&E Comments at 6.)

On the other hand, parties who support designating the distribution utilities (and even some who oppose) acknowledge that the investor-owned utilities are likely the only candidates who can serve the central procurement function in the immediate term.[14] As TURN states, the investor-owned utilities

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[10] *See, e.g.*, AReM Comments at 5, CalCCA Comments at 19-20, Calpine Testimony at A-2.

[11] *See, e.g.*, EnerNOC Comments at 4, SunRun Comments at 7.

[12] *See, e.g.*, PG&E Testimony at 2-21, NRG Testimony at 25-26, White Paper: Resource Adequacy and Wholesale Market Structure for a Future Low-Carbon Power System in California, submitted by SDG&E, PG&E, and SCE (Joint Utilities' White Paper) at 1.

[13] PG&E Reply Testimony at 1-25, SDG&E Comments at 6, SCE Testimony at 14.

[14] *See, e.g.*, CLECA Comments at 7, NRG Comments at 8, ORA Comments at 14, TURN Testimony at 23.

are the "only feasible entities" to serve as central buyers as they "have the resources, the knowledge and experience to take on this task effectively." (TURN Testimony at 23.) ORA also agrees "that the IOUs [investor-owned utilities] are the only practical entities who could centrally procure some portion of multi-year local RA on behalf of the LSEs in the near term." (ORA Comments at 14.) Additionally, PG&E acknowledges that the utilities are likely the only candidates to perform this function in the immediate term, although they do not believe immediacy is required. (PG&E Opening Testimony at 1-25.)

#### 3.1.1.2. Special Purpose Entity

SDG&E and PG&E advocate for a special purpose entity (SPE) to serve as the central buyer. A SPE may be a new state agency or private entity selected through a competitive solicitation process or through legislation. SDG&E and PG&E propose that an SPE collaborate with the CAISO and the Commission to select an optimal portfolio to meet local needs.[15] SDG&E believes an SPE is the ideal central buyer because such entity would be financially stable, neutral, and subject to Commission oversight. (SDG&E Comments at 7.) PG&E favors an SPE because it believes the entity could engage in policy-based procurement without the complications of utility procurement. (PG&E Opening Testimony at 2-20.)

The primary drawback with a governmental SPE, as raised by multiple parties, is the substantial time and expense involved in establishing an independent governmental entity, including the potential for required legislation to do so.[16] Parties acknowledge that adopting this proposal would carry

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15 PG&E Testimony at 2-20, SDG&E Testimony at 5.

16 *See, e.g.,* AReM Comments at 8, CalCCA Comments at 20, CLECA Comments at 8, ORA Comments at 17, PG&E Testimony at 2-20.

administrative and legislative hurdles that would delay use of an SPE for an unknown period. Another criticism expressed by parties is that a third-party entity that purchases and resells capacity in the wholesale market would to some degree be subject to the Federal Energy Regulation Commission's (FERC) jurisdiction, which could potentially lead to conflicts between federal policy and the state's environmental goals. (*See, e.g.*, CalCCA Comments at 20.)

#### 3.1.1.3. CAISO

A third proposal (offered by CalCCA, Calpine, Middle River, NRG, and WPTF) identifies the CAISO as the central buyer.[17] Some parties propose the CAISO act as a central buyer using various procurement mechanisms (*e.g.*, Calpine, CalCCA) while others propose that the CAISO serve as the administrator of a centralized capacity market (*e.g.,* WPTF). Proponents view the CAISO as an ideal central buyer because it is governed by tariffs and is an independent organization with transparent procurement. (*See* Calpine Testimony at A-2.) CalCCA believes the CAISO has the tools and legal authority to spread costs across the utilities' service territories on cost-of-service rates, if contract negotiations fall through. (CalCCA Testimony at 22.)

Other parties raise concerns with the CAISO serving as the central buyer. Parties note the potential conflict with FERC's involvement in California's capacity market and the state's environmental goals.[18] SDG&E cites the significant time involved in establishing the CAISO as the central buyer, as it would require a stakeholder initiative process to design a new market structure

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[17] CalCCA Comments at 20, Calpine Testimony at A-2, Middle River Comments at 9, NRG Testimony at 9, WPTF Testimony at 7.

[18] *See* CLECA Comments at 9, Joint Environmental Parties Comments at 7-8, ORA Comments at 16-17, TURN Testimony at 25.

and tariff amendments for approval by FERC. (SDG&E Comments at 7.) The Joint Environmental Parties add that the CAISO has little experience in administering competitive resource solicitations. (Joint Environmental Parties Comments at 8.)

Particularly noteworthy, however, is the CAISO's own response that it "will not voluntarily accept a role as central buyer, and the Commission should explore other options." (CAISO Comments at 5.)

#### 3.1.1.4. Discussion

One distinguishing feature of parties' proposals is the amount of time it would take to establish the central buyer before procurement could begin. For example, proposals in favor of creating a special procurement entity would require considerably more time to implement than proposals designating the existing distribution utilities as the central buyer. As discussed in the Track 1 decision, the Commission intends to implement a central buyer framework for the 2020 RA compliance year. To achieve this objective, the Commission plans to move expeditiously to implement a central buyer mechanism for that timeline.

To that end, we conclude that designating the distribution utilities as the central buyers for their respective TAC areas is the most practical, feasible solution in the near term. Weighing the benefits and concerns raised by parties, we agree with parties who recognize that, at this time, the utilities are the only candidates with "the resources, knowledge and experience"[19] to procure local reliability resources on behalf of all LSEs without excessive delay.

The Commission is unpersuaded that either an SPE or the CAISO could readily take on the central procurement role in the near term, given the noted

[19] *See* TURN Testimony at 23.

obstacles. Designating a special governmental entity would require administrative and legislative processes that would cause substantial delay. There is insufficient record support for a non-governmental third-party entity to take on the significant task of procuring state-wide local RA; however, the Commission is open to considering such an entity at a future date if viable solutions emerge. Likewise, designating the CAISO involves its own administrative challenges, as well as potential federal jurisdictional conflicts. Moreover, the CAISO's statement that it is unwilling to accept the central procurement role voluntarily underscores our finding that the CAISO is not an appropriate entity to take on this role.

The Commission acknowledges the distribution utilities' concerns regarding debt equivalency and potential financial risks associated with the procurement function. However, at this time, we find the record does not provide tangible support to allow the Commission to ascertain the probability or severity of these scenarios. SDG&E acknowledges that credit rating agencies consider factors "such as robust cost-recovery mechanisms (such as the Cost Allocation Mechanism [] in the calculation of power purchase agreement [] debt equivalence, and a legislative- or regulatory-backed recovery mechanism will be treated at a discounted level," although they may not be fully discounted or considered risk-free. (SDG&E Comments at 6.) Going forward, the Commission welcomes the utilities to offer supporting documentation should the central procurement function result in negative financial impact to the distribution utilities.

Additionally, the Commission acknowledges that some parties raise questions regarding whether state law precludes the Commission from directing the distribution utilities to act as central buyers. Specifically, the Joint DR Parties and AReM assert that the utilities may not have authority to act as central buyers, citing Pub. Util. Code § 380(c) and (d), which provide that "[e]ach load-serving entity" shall maintain generation and demand response capacity that are adequate to meet their load requirements and that the capacity or demand response shall be deliverable "to locations and at times as may be necessary to maintain electric service system reliability and local area reliability."[20]

This excerpt, however, cannot be read in isolation without considering the context of Section 380. Section 380(h) directs the Commission to "determine and authorize the most efficient and equitable means for achieving" a broad list of RA goals, including ensuring that economical generating capacity is retained, that generating capacity and demand response costs are equitably allocated, and that the broad objectives of Section 380 are met. In order to meet these goals, Section 380(i) provides that the Commission may "consider a centralized resource adequacy mechanism among other options."

In addition, the State Legislature recently modified Section 380(h) to add another goal to the RA objectives, directing the Commission to "[minimize] the need for backstop procurement by the Independent System Operator."[21] This additional objective, in light of the other RA objectives in Section 380, underscores the Commission's duty to ensure adequate resource availability for grid reliability regardless of which load serving entity offers service. The Commission thus finds AReM and the Joint DR Parties' position without merit and unsupported by a full reading of Section 380.

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[20] AReM Comments at 7-8, Joint DR Parties Comments at 8.

[21] Senate Bill No. 1136 (2018 Hertzberg), Pub. Util. Code Section 380, subd. (h)(7).

Finally, the Commission finds that many of the concerns raised in opposition to distribution utility procurement pertain to concerns about neutrality, transparency, and anti-competitive effects. The Commission specifically addresses these concerns in Section 3.1.9 below and believes that the safeguards and measures adopted in this decision should greatly mitigate these concerns.

For these reasons, the Commission concludes that the distribution utilities shall serve as the central buyer for their respective distribution service areas. As this is the initial implementation of a multi-year local program that may need further refinement in the future, the Commission will continue to monitor and evaluate the central procurement function and may modify the role or designate a different central buyer as appropriate in future years.

#### 3.1.2. Scope of Central Procurement

The Commission next considers the scope of local RA that shall be centrally procured by the central buyers. Parties generally propose either a full procurement or residual procurement model, with some variations.

PG&E and Energy Division support a full procurement model. Both proposals would operate similarly, as follows: A central procurement entity procures the entire amount of required local RA, and LSEs do not receive individual local requirements. LSEs that have procured local resources may offer those resources to the central entity by bidding into the procurement entity's solicitation. If an LSE-procured local resource is not selected by the central buyer, the local resource would still be eligible to count towards the LSE's system or flexible RA obligations, if applicable.[22]

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[22] Energy Division Proposal at 15-16, PG&E Opening Testimony at 2-1, 1-4.

SCE offers a hybrid full procurement model in that LSEs no longer receive a local requirement. LSEs will continue to procure RA to meet system and flexible requirements "with the assumption that their procurement objective will be to secure the least-cost resources to meet their RA needs." If, in doing so, the least-cost resources also meet local area needs, the local resource may reduce the total local RA amount the central buyers must procure if certain conditions are met. Namely, the LSE must voluntarily "show the resource for each annual and monthly showing in which it has contracted for the resource."[23]

Several parties advocate for a residual procurement model, including CalCCA, CLECA, the Joint Environmental Parties, NRG, ORA, SDG&E, Shell, and WPTF.[24] The proposed residual procurement models generally function as follows: an LSE receives a local RA requirement (either an optional or required allocation) to procure its own local resources. An LSE makes its local RA showing and then based on an assessment of what is not procured, the central buyer procures for an individual or collective deficiency. In effect, the central buyer acts in a backstop role to procure local resources to meet collective deficiencies. CalCCA proposes that LSEs receive an optional local allocation and the central buyer procures a set amount of local RA capacity (10% in Year 1 and 5% in Year 2), after which any deficiencies are cured through backstop procurement. (CalCCA Testimony at 6.)

Some parties note that disaggregation to sub-local areas is a minimum requirement under a residual procurement approach since continued

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[23] SCE Reply Comments on SCE Proposal at 4.

[24] CalCCA Testimony at 6, CLECA Comments at 11, Joint Environmental Parties Testimony at 9, NRG Comments at 8, ORA Comments at 18, SDG&E Testimony at 4, Shell Comments at 3, WPTF Testimony at 5.

aggregation of local areas will lead to ongoing risk of backstop procurement in some sub-areas and over-procurement in other areas.[25] The CAISO favors disaggregation by local and sub-local capacity areas, arguing that this would more closely tie procurement to local capacity needs and operational requirements. (CAISO Comments at 5.) Under its transitional proposal, PG&E recommends disaggregating certain local capacity areas in its service territory, at least until its long-term central buyer structure is operational. (PG&E Opening Testimony at 1-7.)

#### 3.1.2.1. Discussion

One identified advantage of full procurement is that the central buyers can procure more efficiently by selecting necessary and preferred resources at the lowest cost. By contrast, under a residual approach where LSEs secure their own resources, a procured resource may not be the most effective, potentially leading to inefficient procurement and collective deficiencies that result in backstop procurement. (*See* PG&E Reply Testimony at 1-7.)

Another advantage of full procurement is the ease of administration as it eliminates the need to track LSE self-provided portfolios and fairly allocate local requirements and costs to individual LSEs. Full procurement can also effectively account for load migration addressing stranded cost concerns. Under a residual framework, an LSE who experiences load migration may be potentially stranded with these resources and costs. The uncertainty around load migration discourages LSEs from procuring too far out given that they do not know if they will have a particular set of customers in the future. A full procurement model

[25] *See, e.g.*, Calpine Testimony at A-3, PG&E Reply Testimony at 1-8, SCE Testimony at 12.

can accommodate load migration by increasing and decreasing cost responsibility to LSEs gaining and losing load. (*See id*. at 1-12.)

Additionally, full procurement allows for an equitable allocation of costs based on LSEs' respective load shares, whereas under a residual framework, an LSE who procures more effective resources than other LSEs can still face collective deficiency costs that are proportionally shared by all LSEs. (*Id*. at 1-11.)

By contrast, supporters of a residual procurement model identify several benefits. A residual model offers individual LSEs the flexibility and autonomy to procure local resources based on their (and their customers') particular objectives or preferences.[26] The residual model also gives LSEs certainty that a procured local resource will receive local RA credit rather than leaving that determination to a central buyer. Another benefit of residual procurement is that LSEs, such as CCAs, retain the buying power and corresponding value proposition that they can offer their customers. (*See, e.g*., Joint DR Parties Testimony at 13.)

In terms of SCE's hybrid proposal, a few parties argue that it does not adequately address cost allocation as it is unclear how LSEs' self-procured local RA would be incorporated into the central cost allocation.[27] Thus an LSE who procures a local resource would end up paying the full cost of the resource, as well as their share of residual procurement undertaken by the central buyer.[28] Parties that support SCE's proposal recommend modifying it to be an LSE-based requirement and pointing to SDG&E's proposal as a better alternative. In reply

[26] *See, e.g*., CalCCA Comments at 13, CLECA Comments at 12, SCE Comments at 8.

[27] S*ee, e.g*., CalCCA Comments on SCE Proposal at 7, CLECA Comments on SCE Proposal at 3, SDG&E Comments on SCE Proposal at 3.

[28] PG&E Comments on SCE Proposal at 5, SDG&E Comments on SCE Proposal at 3.

comments, SCE provides further refinements to its proposal, including clarifications to the cost allocation for LSE-procured local resources.[29] However, at this time, the Commission finds insufficient record support for SCE's proposal and that even with proposed modifications, further development would be required. We thus decline to adopt SCE's proposal at this time.

As discussed in the Track 1 decision, the Commission seeks a multi-year framework that will, among other things, reduce costly out-of-market RA procurement due to procurement deficiencies, account for increased load migration, and ensure that necessary resources are procured in an orderly manner. (D.18-06-030 at 24-25.) The Track 1 decision also directs any proposal involving more than one procurement entity – as a residual approach effectively is – to demonstrate it can "address equitable allocation of costs to all customers" and "ensure cost-effective, efficient and coordinated procurement for each local and sub-local area within the TAC." (*Id*. at 33.)

The Commission is not persuaded that any of the residual proposals can address the above objectives. A residual framework creates administrative complexities in that the central buyers must track an increasing number of LSE portfolios and costs over a multi-year period, allocate capacity requirements to LSEs, and determine what deficiencies remain. The Commission agrees that when LSEs procure on an individual basis, they are likely to procure the resource that best meets their individual objectives (*e.g*., lower cost, or local benefits such as providing jobs) rather than the most effective resource for overall grid reliability, which can lead to collective deficiencies.

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[29] SCE Reply Comments on SCE Proposal at 3.

Additionally, a residual framework under the current RA system that aggregates local capacity areas will lead to continued risk of backstop procurement in certain areas, as well as unfair cost allocation since costs vary across local and sub-local areas. The Commission cannot address this problem by simply disaggregating local capacity areas. The rationale for aggregating local areas originally was that market power issues may arise for small sub-local areas with capacity constraints. This remains an ongoing concern and therefore, the Commission does not consider disaggregation a viable option at this time.

On the other hand, full procurement permits the central buyers to secure a portfolio of the most effective local resources, mitigating the need for costly backstop procurement in certain local areas. Full procurement allows the distribution utilities to use their purchasing power in constrained local capacity areas, further ensuring a least-cost solution for all customers and equitable cost allocation. This model also allows the central buyers to adapt to load uncertainty and migration by adjusting local RA cost responsibility to LSEs based on actual load rather than based on forecasted load. Full procurement also ensures that sufficient capacity is procured to meet local needs over a multi-year duration, reducing the likelihood that strategically-located local resources will seek retirement. Lastly, under full procurement, local procurement can be coordinated by the central buyers with California's environmental policy goals and preferred resource procurement mandates in mind.

In light of the objectives outlined in the Track 1 decision, the Commission adopts a full procurement model in which the central buyers (one per TAC area) shall procure for local resources within their service areas to effectively and efficiently meet local area needs and reduce backstop procurement.

### 3.1.3. Duration of the Multi-Year RA Program

The Commission next considers the duration of a multi-year forward RA program. In the Track 1 decision, the Commission directed parties to propose a multi-year local RA requirement with a three- to five-year duration in Track 2 of the proceeding, to be implemented beginning with the 2020 RA program year. (D.18-06-030 at 28.)

Energy Division and a few parties, including Diamond/Sentinel, IEP, PG&E, and SDG&E, support a five-year forward multi-year local requirement.[30] Middle River supports either a three- to five-year requirement.[31] Supporters of a five-year duration believe that longer duration contracts may provide financial stability and greater transparency for necessary resources, while giving resources that are not contracted an important signal that may inform retirement decisions.[32] Others state that generators can offer more efficient pricing on a longer-term contractual basis. (*See* Middle River Testimony at 6.) Some argue that a longer duration provides greater opportunity for investment and development of new generation and transmission alternatives that can compete with existing generation. (*See* PG&E Reply Testimony at 1-17.)

A broad range of parties support a three-year duration, including AReM, CAISO, CalCCA, Calpine, CLECA, GPI, the Joint DR Parties, the Joint Environmental Parties, Middle River, NRG, ORA, Shell, SCE, and TURN.[33]

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30 Diamond/Sentinel Comments at 1, Energy Division Proposal at 18, IEP Testimony at 11, PG&E Reply Testimony at 1-17, SDG&E Testimony at 25.

31 Middle River Testimony at 6.

32 *See, e.g.,* Diamond/Sentinel Comments at 1, IEP Testimony at 11, PG&E Opening Testimony at 1-13.

33 AReM Testimony at 5, CAISO Testimony, Chapter 2 at 1, CalCCA Testimony at 4, Calpine Comments at 5, CLECA Comments at 12, GPI Comments at 3, Joint DR Parties Testimony at 4,

Proponents of a shorter duration cite the many changes that can arise in five years (such as transmission upgrades and new generation) as a basis for why procurement beyond three years greatly increases the risk of over-procurement.[34] ORA and the Joint Environmental Parties reference PG&E's proposed transmission solution in the South Bay/Moss Landing sub-area as an example of how quickly solutions can be deployed to reduce local needs. PG&E's proposed solution was approved by the CAISO in March 2018 and planned to be in place for 2019.[35] Others note that the longer the forward duration period, the more impactful changes in load migration become. (*See* SCE Testimony at 5.)

Some parties claim that the arguments made in favor of a five-year duration can likewise be made in support of a three-year period, while avoiding added risks and preserving flexibility.[36] The Joint Environmental Parties comment that those advocating for a five-year requirement "have not adequately explained why five-year contracts provide additional reliability benefits or savings" over three-year contracts. (Joint Environmental Parties Comments at 5.) Supporters of a three-year duration urge the Commission to adopt and evaluate a shorter duration before implementing a five-year requirement that locks in resources where local capacity may no longer be needed.[37]

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Joint Environmental Parties Testimony at 7, Middle River Testimony at 7, NRG Comments at 8, ORA Comments at 20, Shell Testimony at 4, SCE Testimony at 15, TURN Testimony at 14, WPTF Testimony at 8.

[34] *See, e.g.,* CLECA Comments at 13, IEP Testimony at 22, Joint Environmental Parties Testimony at 7, TURN Testimony at 22.

[35] Joint Environmental Parties Testimony at 7-8, ORA Comments at 21.

[36] *See, e.g.*, Joint Environmental Parties Comments at 7, ORA Comments at 21.

[37] *See, e.g.*, AReM Testimony at 6, Joint DR Parties Testimony at 4, Joint Environmental Parties Testimony at 7.

The Commission observes a consensus for a three-year duration among a broad group of parties and is persuaded by the arguments made in support thereof. We agree that local requirements can significantly change from year to year as transmission projects come online and modeling assumptions change. Adopting a shorter duration will likely reduce the financial risks and costs of over-procurement of local RA, as identified by parties. A three-year requirement still provides preferred alternatives an opportunity to develop and reduce local capacity need in later years. Moreover, the utilities' reservations about negative financial risks and debt equivalency as a result of serving as the central buyers may be minimized with a shorter procurement duration.

Accordingly, the Commission adopts a minimum three-year forward multi-year RA requirement. The minimum requirement does not preclude contracts exceeding three years and we encourage the central buyers to enter into longer-term contracts if it is in ratepayers' interest to do so.

#### 3.1.4. Amount of Central Procurement

The Commission next considers the specific percentage of local RA capacity that shall be centrally procured in each forward year. To assess the specific amount that the central buyers shall procure, the Commission first evaluates the appropriate inputs and studies that shall inform the local RA requirements.

##### 3.1.4.1 Local RA Studies

In the Track 1 decision, the Commission recognized the need for further study in setting procurement requirements, while also continuing to rely on existing studies to move forward with the initial implementation of multi-year local procurement and maintain the integrity of the RA program. The Commission concluded that the CAISO's existing Local Capacity Requirement

Technical Studies (LCRTS) would be a primary input into the Commission's determination of multi-year local RA needs. (D.18-06-030 at 34.) Under the existing RA program, the CAISO produces one-year and five-year ahead local capacity technical studies that identify the minimum local resource capacity required in each local area. The studies are provided to the Commission for consideration in the RA proceeding. In the Track 1 decision, the Commission acknowledged the need for further studies used to set RA requirements and directed Energy Division to propose such studies in Track 2. (*Id*.)

The CAISO affirms that it will adjust its studies as needed for a multi-year RA framework. (CAISO Testimony, Chapter 2 at 6.) In its Track 2 proposal, Energy Division recommends that the Commission use the CAISO's existing one-year ahead study to develop the Year 1 and Year 2 requirements and use the five-year ahead study to develop the Years 3 to 5 requirements (depending on the adopted duration). (Energy Division Proposal at 10.) Energy Division also recommends that for Years 2 and 3, the CAISO use engineer-managed adjustments to revise the power flow results to account for approved transmission upgrades scheduled for that year. Such adjustments would allow for transmission planning assumptions to be part of the local requirements and minimize the potential for over-procurement of local RA after Year 1. (*Id*.)

Other parties, including AReM, IEP, PG&E, and SDG&E, support the CAISO's LCRTS to be performed for all forward years.[38] SDG&E adds that the study should be updated annually to ensure procurement decisions are aligned. (SDG&E Testimony at 26.) AReM recommends that the CAISO establish a fixed

[38] AReM Testimony at 4,11, IEP Testimony at 15, PG&E Opening Testimony at 2-4, SDG&E Testimony at 26.

amount for the entire period with periodic true-ups to address load migration. (AReM Testimony at 4, 11). PG&E and SCE recommend that the CAISO create a new study window to propose transmission solutions to reduce or address local reliability needs.[39]

The Commission finds the use of the CAISO's existing one- and five-year studies, with the requirement to incorporate engineer-managed adjustments for CAISO-approved transmission projects, to be a reasonable input to inform multi-year local requirements. As proposed by Energy Division, the one-year ahead study will form the basis for local requirements for Years 1 and 2 and the five-year study will inform the Year 3 requirements. If CAISO management approves any transmission upgrades for Years 2 and 3, the CAISO shall incorporate such projects into the associated year's studies through engineer-managed adjustments. The inputs and assumptions for the LCRTS shall be filed in the RA proceeding where parties may file comments. This solution allows the Commission to evaluate the local RA requirements for the initial implementation of the multi-year program without extensive modification to the CAISO's existing studies. It also minimizes the risk that resources will be procured longer than they may need to be, by accounting for new transmission and load forecast assumptions with engineer-managed adjustments.

Additionally, the CAISO offers to produce a study that identifies specific resources deemed essential to reliability in local or sub-local areas (called essential reliability resources or ERRs). (CAISO Testimony, Chapter 3 at 6.) The CAISO states that identifying ERRs may inform the central procurement entity and/or LSEs to make appropriate procurement decisions. While the CAISO's

[39] PG&E Opening Testimony at 2-4, SCE Comments at 10.

study may prove useful, the Commission finds it unnecessary to adopt it at this time since the existing LCRTS identifies essential resources (with effectiveness factors) that can meet capacity needs in local and sub-local areas. However, the Commission concludes that the central buyers should use the CAISO's ERR study or a similar methodology to guide local procurement, in collaboration with the CAISO and Energy Division staff, so as to avoid potential backstop procurement.

#### 3.1.4.2. Specific Percentages for Procurement

In the Track 1 decision, the Commission concluded that in the interest of market certainty in the near term, the percentage for the first year of multi-year local RA procurement should be a 100% requirement. For the second year, to address concerns of potential over-procurement of local RA, the local requirement was set to at least 95%. (D.18-06-030 at 29-30.) The Commission directed parties in Track 2 to propose a "reasonable amount of local RA procurement for Year 3 (and beyond, if a longer program is proposed) basing their proposals on data such as that presented by Energy Division in its [Track 1] proposal." (*Id*. at 30.) The Commission also stated that generally, the procurement requirements should be greater than current voluntary local RA forward procurement levels.

Track 2 proposals cover a broad range of percentages with no general consensus. We note that numerous proposals offer percentages without clarifying what the percentage would be based on, such as adjustments to the LCRTS.

All parties support a continuation of the 100% local procurement requirement for Year 1, although we note some parties offered this support under a residual proposal. Proposals for Years 2 and 3 are summarized as follows: at the high end of the spectrum, Calpine, NRG, PG&E, SCE, and WPTF support a 100% requirement for the entire multi-year duration.[40] The CAISO proposes 100% for Years 1 and 2, and 80% in Year 3. (CAISO Testimony, Chapter 2 at 4.) At the low end, the Joint DR Parties and Shell support a 50% requirement for Year 3.[41] Year 3 proposals cover the widest ground with the majority falling between 70% and 100%.[42]

Proponents of a lower percentage for Year 3 (and in some cases, Year 2) cite arguments similar to those raised in favor of a three-year duration. Parties note that a high percentage requirement increases the risk of over-procurement due to year-over-year variations in local need determination as a result of load forecasts, new generation, transmission upgrades, etc.[43] ORA reiterates the example of PG&E's transmission solution in the South Bay/Moss Landing sub-area (in which local need was reduced from 2,221 MW in 2018 to 1,653 in 2019) in support of a 80% requirement in Year 3. (ORA Comments at 23.)

Supporters of a 100% requirement for the entire duration assert the importance of giving generators certainty as to which resources are needed and minimizing the risk that necessary resources are excluded from procurement. (*See, e.g*., PG&E Reply Testimony at 1-19.) The CAISO supports 100% procurement through Year 2, arguing that analysis of over-procurement risk is overstated "while ignoring the risks of under-procurement, which has both

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[40] Calpine Comments at 5, NRG Testimony at 9, PG&E Reply Testimony at 1-19, SCE Testimony at 15, WPTF Testimony at 4.

[41] Joint DR Parties Testimony at 4, Shell Testimony at 4.

[42] For example, CLECA and TURN support 70%; AReM, CAISO, CalCCA, and ORA support 80%; Energy Division and IEP support 90%; and SDG&E supports 95%.

[43] *See* AReM Comments at 22, ORA Comments at 22, TURN Testimony at 9.

reliability and financial/economic impacts." (CAISO Comments at 6-7.) The CAISO believes that reductions in local capacity requirements "are largely driven by transmission system upgrades, which the CAISO and stakeholders typically know about years in advance" and are therefore included in the CAISO's LCR studies. (*Id*.)

As discussed in the Track 1 decision, we intend to adopt a high percentage of procurement for Years 1 and 2 in an effort to increase certainty and stability for necessary resources, as well as provide market signals for resources that are not contracted. The Commission acknowledges the over-procurement concerns with respect to year-to-year variations in LCRTS results. To that end, the Commission finds that the CAISO's proposal strikes an appropriate balance with a 100% requirement for Years 1 and 2 and an 80% requirement for Year 3. An 80% procurement in Year 3 provides sufficient flexibility for market variabilities that may relieve local constraints in future years, such as development of new generation and transmission upgrades (that have not been incorporated into the engineer-managed adjustments). In conjunction with a shorter three-year forward requirement, we find these percentages will likely minimize over-procurement risk in later years.

In addition to taking these actions to limit risk of over-procurement of the local RA attribute, we further note that any excess local RA resources will nevertheless have value as system (and potentially flexible) RA resources, which mitigates the costs of over-procurement. As with the three-year forward duration, the Commission's adopted percentages of 100% for Years 1 and 2 and 80% in Year 3 are minimum requirements. The minimum percentages do not preclude the central buyers from exceeding those percentages and we encourage the central buyers to do so if it is in ratepayers' interest.

#### 3.1.5. Local RA Procurement Mechanism

We next evaluate which procurement mechanism the central buyers shall use to procure the RA resources. Proposals generally fall into two categories: (1) a competitive solicitation or (2) a centralized capacity market.

##### 3.1.5.1. Competitive Solicitation

Energy Division and several parties, including ORA, PG&E, SDG&E, and SCE, recommend a competitive solicitation process as the local RA procurement mechanism.[44] These proposals largely consist of a solicitation for bids through a request for offers (RFO) for particular RA products within a set timeframe. The RFO is a pay-as-bid mechanism in which the central buyers would award RA contracts based on pre-established criteria.

One noted advantage of the solicitation approach is that it allows the central buyers to compare offers from different resources to reach a competitive outcome. (*See, e.g.,* SDG&E Testimony at 6.) A solicitation also allows for consideration of multiple criteria, in addition to cost and local needs, such as state policy goals and impact on disadvantaged communities.[45] Additionally, RFOs are already widely in use for local RA procurement and are therefore, immediately implementable as compared to the alternatives. (*See* PG&E Reply Testimony at 1-15.)

Opponents of an RFO solicitation argue that selection is based on qualitative criteria that does not give LSEs certainty about procurement or the value of their investment. (*See, e.g.*, Calpine Comments at 4.) The Joint DR

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[44] Energy Division Proposal at 15, ORA Comments at 14, PG&E Opening Testimony at 2-6, SDG&E Testimony at 4, SCE Testimony at 17.

[45] *See, e.g.,* PG&E Reply Testimony at 1-15, SDG&E Testimony at 6.

Parties and EnerNOC argue that the RFO process is not transparent in establishing a market price for services.[46]

#### 3.1.5.2. Centralized Capacity Market

Several parties recommend a centralized capacity market (CCM) as the local RA mechanism, including AReM, Joint DR Parties, Middle River, NRG, Shell, and WPTF.[47] A CCM typically refers to a market clearing mechanism where resources are selected based on whether they bid at or below a single market price, along with consideration of grid reliability constraints. Variations of CCMs are currently used in energy markets around the U.S., such as the New England Independent System Operator and New York Independent System Operator.

Some supporters identify the CAISO or other third-party to act as the administrator of the CCM (*e.g.*, WPTF, Joint DR Parties, Middle River), while others recommend a CCM in lieu of a central procurement entity (*e.g.*, AReM, Shell). Shell proposes implementation of a CCM with a clearing price set for each Local Reliability Area. (Shell Testimony at 7.) WPTF favors a CCM that includes reconfiguration actions to allow for intra-year adjustments. (WPTF Testimony at 8.) EnerNOC recommends a variation in which a central entity manages procurement through technology-enabled live reverse auctions. (EnerNOC Testimony at 4.)

Parties supporting a CCM identify several advantages, including price transparency with a single market price, market liquidity (at least in local areas where more than one resource owner is present), and ease of transactions based

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[46] EnerNOC Comments at 4, Joint DR Parties Testimony at 17.

[47] AReM Comments at 4, Joint DR Parties Testimony at 15, Middle River Testimony at 9, NRG Testimony at 9, Shell Testimony at 7, WPTF Testimony at 5.

on relatively simple clearing parameters.[48] SCE adds that a CCM "provides the appropriate signals and incentives to generators to allow for rational decisions about resource investment or retirement to occur."[49]

Opponents of a CCM model argue that CCMs procure resources solely based on system-wide grid reliability and cost considerations and are thus not set up for targeted procurement for small local and sub-local areas, preferred resources, and/or disadvantaged communities.[50] Another criticism is that a CCM model would likely be regulated by FERC since it involves purchase and sale of wholesale capacity, which exposes California's procurement policies to federal jurisdiction and limits the Commission's ability to oversee procurement with an eye towards state environmental goals.[51] Others cite the administrative hurdles and complexity in establishing a CCM, such as setting demand curves. (*See, e.g.*, Shell Testimony at 10.) Additionally, ORA argues that a CCM could increase ratepayer costs due to increased capacity payments determined by the market clearing price which would be applied to all cleared capacity, as well as potential increased costs to support state preferred resources through a mechanism such as a minimum offer price rule. (ORA Comments at 12.)

#### 3.1.5.3. Discussion

In weighing the benefits and concerns raised by parties, the Commission is persuaded by the arguments in favor of a competitive solicitation process. An RFO process is better aligned with the state's energy policies in that it gives the

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48 *See, e.g.,* AReM Comments at 3, Shell Testimony at 4.

49 SCE Testimony at 14. *See also* Middle River Testimony at 6, WPTF Testimony at 6.

50 *See, e.g.*, CLECA Comments at 10, ORA Comments at 12.

51 *See, e.g.,* ORA Comments at 4, PG&E Reply Testimony at 1-16, Shell Testimony at 8, TURN Comments at 8.

central buyers the flexibility to select resources based on targeted criteria, including broader environmental goals, such as preferred resources. An RFO also allows targeted procurement necessary for addressing reliability in certain local and sub-local areas. A CCM, by design, procures only based on grid reliability and cost criteria and thus cannot engage in such targeted procurement. Additionally, the RFO process is already successfully used by LSEs for RA procurement, and can be implemented relatively quickly in much the same way as it is currently occurring without reconfiguration. Establishing a new centralized capacity market, on the other hand, would be a complex undertaking with significant risks and unclear benefits. In the interest of providing market certainty and implementing a multi-year RA program for the 2020 compliance year, the Commission adopts a competitive solicitation process to be conducted by the central buyers for multi-year local RA procurement. In the sections below, we discuss the specific implementation requirements for the solicitation process.

#### 3.1.6. Resources To Be Solicited

The Commission next assesses the types of resources that may bid into a solicitation administered by the central buyers. PG&E and Energy Division propose that any existing or potential new resource without a contract can bid into the solicitation, as can any existing LSE-contracted local RA resources.[52] WPTF and the Joint DR Parties advocate for Demand Response (DR) resources being eligible to bid into the procurement mechanism.[53] PG&E and Energy Division recommend that only Cost Allocation Mechanism (CAM) resources and those procured by the central buyer should count towards reducing the local RA

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52 Energy Division Proposal at 15, PG&E Opening Testimony at 2-5.

53 Joint DR Parties Testimony at 5, WPTF Testimony at 4.

requirements.[54] SDG&E suggests that all resources receiving CAM and CAM-like treatment, including DR, could be excluded from an RFO since their capacity is already being allocated to all customers.[55]

Energy Division and other parties favor keeping RA attributes bundled through the RFO process such that any local resource capable of providing other collateral RA products would be required to sell the other RA products (*e.g.*, local RA with the associated flexible attribute).[56] Energy Division proposes that LSEs receive credits for any system or flexible capacity procured during the local RA or backstop processes, based on coincident load shares. (Energy Division Proposal at 15.)

Energy Division also recommends that the central buyers procure dispatch rights along with the local RA products, if applicable, to "help ensure that the local resource fleet is subject to the [Commission's] least cost dispatch rules (ensuring locational price stability)." (*Id*. at 16.) SCE states that if a contract conveys the dispatch rights, the Commission's existing Least Cost Dispatch standard should be applicable to the dispatch of the resource procured. (SCE Testimony at 9). Calpine expresses concern with requiring acquisition of dispatch rights to resources used to satisfy local requirements, given that an LSE that contracted for RA only cannot provide dispatch rights that it does not control. (Calpine Comments at 15.) PG&E shares Calpine's concern. (PG&E Reply Comments at 19.)

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[54] Energy Division Proposal at 16, PG&E Reply Testimony at 1-7.

[55] SDG&E Testimony at 20.

[56] *See, e.g.*, Energy Division Proposal at 15, Joint Utilities' White Paper at 18, PG&E Opening Testimony at 2-6, SDG&E Testimony at 7.

PG&E proposes that CAM be expanded to include non-Renewable Portfolio Standard (RPS) utility-owned generation (UOG) and the utility's non-RPS resource contracts. (PG&E Opening Testimony at 2-11). PG&E believes applying CAM to these resources in local areas will fairly allocate the costs and benefits to all LSE customers given that these resources provide a foundation for the CAISO grid. Relatedly, SDG&E proposes that the central buyer's portfolio automatically include non-CAM local renewables and/or preferred resources, CAM and CAM-like resources (*e.g.*, Demand Response Auction Mechanism (DRAM) resources), and non-CAM UOG. (SDG&E Testimony at 20.) Some parties oppose expansion of CAM for this purpose, including AReM and Calpine.[57]

#### 3.1.6.1. Discussion

The Commission previously adopted an open competitive solicitation process in D.04-12-048, which approved the investor-owned utilities' long-term procurement plans. In that decision, one requirement of the solicitation process was that "[a]ll-source open solicitations need to be transparent and competitive, and in addition, need to be open to all resources (conventional/renewable – turnkeys, buyouts and PPAs [power purchase agreements])." (D.04-12-048, Ordering Paragraph 26.)

In consideration of parties' proposals, as well as the adoption of the all-source open solicitation process in D.04-12-048, the Commission concludes that the central buyers shall use similar requirements for their RFO solicitation process. Accordingly, the Commission directs the central buyers to run an all-source solicitation that is transparent, competitive, and open to all resources.

57 AReM Comments at 16, Calpine Comments at 13.

Any existing local resource that does not have a contract, any new local resource that can be brought online in time to meet solicitation requirements, or any LSE or third-party with an existing local RA contract may bid into the solicitation. If an LSE-procured local resource is not selected by the central buyer, the local resource may still count towards the LSE's system or flexible RA obligations, if applicable. RA attributes shall remain bundled, and LSEs shall receive credits for any system or flexible capacity procured during the local RA or backstop processes, based on coincident load shares, as is currently done with CAM resources.

The Commission also agrees with proposals stating that CAM resources[58] and local DR resources should reduce the local RA amount that the central buyers must procure. For local DR resources, it is reasonable to continue to treat DR resources as is currently done in the year-ahead timeframe. The load impact protocol studies currently cover a ten-year forward window. The amount counted shall be based on the applicable three-year period of the most recent load impact protocol studies after any Energy Division adjustments, as is the current practice for determining the qualifying capacity (QC) value of DR resources on a one-year ahead timeframe.

Relatedly, SSWG voices concern over the treatment of DR resources under a multi-year framework. Members contend that a requirement to obtain valid resource IDs from the CAISO in advance of a year-ahead RA showing is unduly challenging.[59] At this time, however, investor-owned utility DR is allocated as a

[58] A CAM resource refers to resources procured for reliability purposes through the cost allocation mechanism adopted in D.06-07-029, and further expanded and refined in subsequent decisions.

[59] SSWG Proposal at A-3.

credit to all LSEs and unless that is modified, obtaining a CAISO resource ID in the year-ahead timeframe is unnecessary, rendering this concern moot. Moreover, it is premature to address counting of DRAM resources under a multi-year framework as that program has thus far not been renewed beyond 2019.

The Commission finds insufficient record support at this time to require the central buyers to acquire dispatch rights alongside RA capacity. However, we do require the central buyers to include dispatch rights in their solicitations, as an optional term that bidders are encouraged to include. We also strongly encourage the central buyers to procure dispatch rights along with the RA capacity, whenever doing so is in the financial interest of all ratepayers (*e.g.*, when the benefits of least-cost dispatch requirements outweigh increased contract costs).

Finally, we find insufficient record support for PG&E and SDG&E's proposals to expand CAM to include certain utility-owned resources. However, it is reasonable for the investor-owned utilities to bid their own resources into the solicitation process at their levelized fixed costs and we direct the utilities to do so.

#### 3.1.7. Solicitation Selection Criteria

Parties offer criteria to determine how local resources should be selected by the central buyers. PG&E recommends that after the solicitation, the central buyer develops at least two portfolios: a "least cost" portfolio based on lowest overall cost and a "preferred resources" portfolio based on objectives defined by the central buyer to achieve state policy goals, such as preferred resources and energy storage mandates. (PG&E Opening Testimony at 2-6.) Energy Division recommends that the "most effective, efficient, and economical resources" are awarded contracts as determined by the central buyer using least cost, best fit principles. (Energy Division Proposal at 16.)

Additionally, Energy Division proposes a set of six selection criteria that should be considered in establishing quantitative and qualitative criteria to guide procurement. The criteria include: (1) future needs in local and sub-local areas, (2) local effectiveness factors, as published in the CAISO's LCRTS, (3) costs, (4) operational characteristics of the resources (including efficiency, age, flexibility, facility type), (5) location of the facility (with consideration for disadvantaged communities), and (6) costs of potential alternatives. (Energy Division Proposal at 23-25.) Energy Division proposes that "[t]he [central buyer] will need to work with CAISO, the CPUC, and others to ensure that the local procurement not only meets California's reliability goals, but also effectively addresses the state's greenhouse gas and environmental justice goals." (*Id*. at 25.)

The Joint Environmental Parties contend that Energy Division's proposal fails to elaborate on how these criteria would be applied and "whether this approach provides sufficient assurance that preferred resources in local areas would ultimately be contracted for their capacity value." (Joint Environmental Parties Comments at 9.) They add that "[i]f new preferred resources procurement under the IRP or other mechanism is location-agnostic or not well coordinated with effectiveness from a local capacity perspective, opportunities to retire polluting facilities will be squandered." (*Id*.)

In D.04-12-048, the Commission approved specific all-source solicitation selection criteria to be used in a utility's long-term procurement processes. In pertinent part, the criteria for all-source open solicitations included:

(1) The first priority shall be "cost-effective energy efficiency and demand-side resources," with "renewable generation [] to be procured to the fullest extent possible…"

(2) Investor-owned utilities will "employ the Least-Cost Best-Fit methodology when evaluating PPAs and utility-owned bids in an all-source open RFO, taking into account the qualitative and quantitative attributes associated with each bid."

(3) "GHG [Greenhouse Gas] adders are to be used for bids in all-source open RFOs." (D.04-12-048 at 126.)

In D.07-12-052, the Commission directed investor-owned utilities to consider additional criteria for procurement. In particular, the Commission added considerations for determining "project viability" and giving greater weight to "disproportionate resource sitings in low income and minority communities, and environmental impacts/benefits (including Greenfield vs. Brownfield development)." (D.07-12-052 at 157.)

The Commission finds the above criteria adopted for solicitations administered by the utilities to serve as a useful, reasonable guide for consideration in the selection of local resources. The Commission also finds that the six selection criteria proposed by Energy Division should be used to guide the quantitative and qualitative criteria employed in the central buyers' all-source solicitations. To that end, the Commission adopts similar procurement rules to guide local procurement by the central buyers, as follows:

The central buyers shall evaluate resources using the least-cost best-fit methodology adopted in D.04-07-029.[60] The least-cost best-fit methodology employed shall include the following selection criteria:

[60] "Least-cost best-fit" refers to the selection of resources that are least cost, including the direct costs of energy generation and any indirect costs due integration of the resource and needed

(a) Future needs in local and sub-local areas;

(b) Local effectiveness factors, as published in the CAISO's LCRTS;

(c) Resource costs;

(d) Operational characteristics of the resources (efficiency, age, flexibility, facility type);

(e) Location of the facility (with consideration for environmental justice);

(f) Costs of potential alternatives; and

(g) Greenhouse Gas adders.

The Commission believes the listed criteria are sufficient to guide the central buyers through the initial local procurement for the 2020 compliance year. However, we recognize that further refinements to the criteria may be necessary through a working group or through additional proposals.

#### 3.1.8. Cost Allocation

The Commission next considers how costs associated with the central procurement function will be appropriately allocated and recovered. Energy Division, PG&E and SCE support the use of the CAM to facilitate an equitable allocation of costs for resources procured by the central buyer.[61] SDG&E proposes cost recovery through non-bypassable charges.[62] No parties opposed these proposals, nor did any other party offer a developed cost recovery alternative applicable to the distribution utilities as central buyers. PG&E proposes that the central buyer's costs to be recovered will include (but not be

transmission investment. In addition, utilities are required to consider resources that best fit their system needs.

[61] Energy Division Proposal at 18, PG&E Opening Testimony at 2-10, SCE Testimony at 10.

[62] SDG&E Testimony at 18.

limited to): contract costs for purchases of local resources, costs for excess local capacity due to decreased load forecast or other changes, administrative costs related to purchase or sale of local capacity, and credit costs related to collateral requirements, credit risks and cashflow variability. (PG&E Opening Testimony at 2-9).

The Commission previously authorized the CAM to allocate costs for investor-owned utility's procurement of generation required to meet system and local reliability needs on behalf of all LSEs. (*See* D.06-07-029, D.13-02-015.) In designating that the investor-owned utilities procure new generation through long-term PPAs, the procured capacity rights were allocated among all LSEs in the service territory and in exchange for those benefits, the LSEs' customers (termed "benefiting customers")[63] paid for the net cost of the capacity. Subsequent decisions and regulations have clarified and amended the CAM.[64] In D.13-02-015, the Commission authorized CAM to allocate costs to LSEs for generation required to meet local reliability needs.

Additionally, the State Legislature recently amended Pub. Util. Code § 365.1 to increase direct access "gigawatt hours and apportion that increase among the service territories of the electrical corporations," while maintaining grid reliability and facilitating the Commission's procurement goals.[65] As discussed earlier, the Legislature also modified Section 380 to direct the

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[63] Benefitting customers have been defined as all bundled service, direct access, and community choice aggregator customers. Benefitting customers are also customers who are located within a utility's distribution territory who take service after the date the new generation goes into service. (D.06-07-029, footnote 21.)

[64] *See* D.07-09-044, D.08-09-012, D.11-05-005, D.13-02-015, and D.14-02-040. The CAM is codified in Pub. Util. Code § 365.1(c).

[65] Senate Bill No. 237 (2018 Hertzberg).

Commission to "[minimize] the need for backstop procurement by the Independent System Operator."[66] These legislative developments further emphasize the Commission's responsibility to ensure adequate resource availability and appropriate allocation of those costs to retail customers in order to achieve a clean, reliable grid.

The Commission seeks a cost recovery mechanism in this proceeding that both facilitates the central buyers' efficient procurement of local resources, as well as provides necessary recovery of costs incurred by the central buyers to ensure financial stability for the distribution utilities. In light of the Commission's previous decisions authorizing the CAM for procurement required to meet local reliability needs, we find the CAM recovery mechanism to be appropriate for the multi-year procurement process. Accordingly, we apply the CAM methodology as the cost recovery mechanism to cover the procurement costs incurred by the central buyers. Additionally, the administrative costs incurred by the central buyers in serving the central procurement function shall be recoverable under the cost allocation mechanism. The central buyers are directed to establish a balancing account in order to facilitate the cost recovery process.

#### 3.1.9. Procurement Oversight

Several parties urge the Commission to adopt safeguards before designating the distribution utilities to act as the central buyers in order to mitigate conflict of interest, transparency, and anticompetitive concerns.[67] Energy Division recommends that the central buyers should be subject to (1) a

[66] Senate Bill No. 1136 (2018 Hertzberg), Section 380, subd. (h)(7).

[67] *See supra* at Section 3.1.1.1.

stakeholder monitoring committee, similar to the CAM Procurement Review Group (PRG), (2) an Independent Evaluator (IE) to monitor all solicitations and transactions, and (3) a public report prepared by the IE following each solicitation that analyzes local procurement, market power, and aggregate pricing. (Energy Division Proposal at 15.) Energy Division also proposes that the distribution utilities establish an independent procurement arm, which would be subject to competitive neutrality rules, as adopted in D.13-12-029. (*Id*.) CLECA and ORA support Energy Division's proposal.[68] PG&E supports the concept of an independent evaluator overseeing the central procurement process. (PG&E Reply Testimony at 1-26.) No other parties propose a developed alternative to these oversight mechanisms.

The Commission's objective in adopting safeguards to oversee the central buyers' procurement and solicitation process is to provide LSEs and other market participants with reasonable assurances as to the neutrality and transparency of the process, while also giving the central buyers appropriate flexibility and discretion to efficiently procure local resources given the existing time constraints in the RA timeline. We address potential safeguards and mitigation measures in turn.

#### 3.1.9.1. Procurement Review Group

The Commission initially established Procurement Review Groups in D.02-08-071 as an advisory group to assess the investor-owned utilities' procurement strategy and processes, as well as specific proposed procurement contracts. The PRG included non-market participants, as well as Energy Division and ORA. (D.02-08-071 at 24.) In D.07-12-052, the Commission

[68] CLECA Comments at 7, ORA Comments at 14.

approved the establishment of a PRG for the CAM process. The decision defined the membership requirements for the CAM PRG, as well as the obligations of participants. (*See* D.07-12-052, Appendix D.) PRG recommendations are deemed advisory to the utility and non-binding. (*Id*. at 119.)

The purpose of the PRG, as originally provided in D.02-08-071, is to routinely consult with the investor-owned utility, and to review and assess the utility's overall procurement strategy and specific proposed contracts and processes. (D.02-08-071 at 25.) D.07-12-052 required the investor-owned utilities to hold a meeting with the independent evaluator, PRG, and Energy Division "to outline their plans and solicit feedback prior to drafting RFO bid documents so that RFO process is improved by the identification of data gaps, confirmation of the fairness of the confidential components of the RFO, and of the compliance with the letter and spirit of Commission policies on procurement practices." (D.07-12-052, Ordering Paragraph 15.) Additionally, "[d]raft bid documents are to be developed under the oversight of an IE, vetted through the PRGs with differences to be resolved by [Energy Division] staff in advance of the public issuance of the bid documents." (*Id*. at Ordering Paragraph 16.)

In light of the Commission's objectives in establishing procurement oversight mechanisms, we agree with Energy Division's proposal to use a PRG to advise in multi-year central procurement as an appropriate safeguard and consistent with past Commission decisions involving utility procurement. Accordingly, we adopt the use of the CAM PRG, as further described in D.07-12-052, to advise the central buyers. The central buyers are required to consult with the CAM PRG members (including Energy Division and an independent evaluator) as they outline procurement plans, draft RFO solicitation bid documents, and collect feedback from market participants regarding the RFO process for potential refinements and modifications. The IE is also required to brief the CAM PRG on key solicitation elements, as described below.

#### 3.1.9.2. Independent Evaluator

The Commission has historically authorized the use of independent evaluators to monitor solicitations by investor-owned utilities. In D.04-12-048, we authorized the retention of an IE to monitor bids involving affiliate transactions, utility-built, or utility-turnkey bidders. That decision adopted parameters for IE retention, which, in pertinent part, included:

(a) The IE "should come equipped with technical expertise germane to evaluating resource solicitation power products. … IEs should have experience analyzing the relative merits of the various types of PPAs. IEs should be able to evaluate PPAs, turn-keys, and IOU-built on a side-by-side basis. An IE should make period presentations regarding their findings to the IOU and to the PRG." (D.04-12-048, Finding of Fact 95.)

(b) The IOUs "may contract directly with IEs, in consultation with their respective PRGs. The IOUs shall allow periodic oversight by the Commission's Energy Division. … Independent evaluators shall coordinate to a reasonable degree with assigned Energy Division management and staff as a check on the process." (*Id*. at Ordering Paragraph 28.)

In D.06-07-029, the Commission required an IE to oversee any competitive RFO administered by the investor-owned utilities that resulted in a contract subject to the CAM. (D.06-07-29 at 28.) In D.07-12-052, the Commission expanded the use of IEs to monitor certain competitive RFOs with additional requirements, including:

(a) The utilities should develop a pool of at least three IEs to be used on a rotating basis for each RFO;

(b) Energy Division should be in involved during the selection process and have the right to final approval of the IE;

(c) The IE report shall be filed with the Commission's Quarterly Compliance Report based on a template developed by the Energy Division;

(d) The utilities, in collaboration with the PRG and Energy Division, shall develop comprehensive conflict-of-interest disclosure requirements for the IE. (D.07-12-052, Ordering Paragraphs 10, 12.)

Given the Commission's history authorizing IEs to oversee solicitations for utility procurement, the Commission agrees with Energy Division's proposal to authorize an IE to monitor the central buyers' solicitation process for local RA procurement, as well as the contract execution process.

Using the above-mentioned decisions as guidance, we approve a similar IE process that should include, but not be limited to, the following: the central buyers are directed to collectively develop a pool of at least three IEs, with the appropriate level of technical expertise and experience, to serve on a rotating basis for solicitations. Energy Division will have final approval over the selection of the IEs. The IE will prepare a report to be submitted on an annual basis to the Commission, which will assess the neutrality of the procurement process, any market power or aggregate pricing concerns, and other relevant issues. The IE will also brief the PRG in its meetings on the procurement process and any concerns related to neutrality, market power, pricing, disadvantaged communities, or other concerns. The central buyers shall permit periodic oversight of the IE process by Energy Division. The central buyers shall rely on the guidance for the IE process provided in D.04-12-048; however, such guidance shall represent a minimum standard for an effective IE process.

#### 3.1.9.3. Portfolio Approval Process

A few parties propose that the Commission and/or the CAISO approve the portfolio of local RA resources selected by the central buyers. PG&E and SDG&E recommend that after the solicitation, the central buyer develops proposed portfolios to be presented to the Commission and the CAISO for approval.[69] ORA suggests that after a solicitation, the central buyer work with the Commission, the CAISO, and non-market participants to select appropriate resources. (ORA Comments at 14.)

In D.07-12-052, as part of the bundled procurement plan requirements, the Commission established a preapproval process for contracts with terms of less than five years. Under the adopted process, if a procurement action complied with the approved methodology, an executed contract of less than five years did not require preapproval and the action could not be subject to after-the-fact reasonableness review. (D.07-12-052, Ordering Paragraph 19).

The Commission's objective in adopting a preapproval mechanism, as discussed in D.07-12-052, is to give the investor-owned utilities achievable standards and criteria for cost recovery, authorize procurement decisions that incorporate the Commission's policy direction, and eliminate the need for after-the-fact reasonableness review of procurement actions that meet certain conditions.[70] Considering these objectives, we deem it appropriate to adopt a similar preapproval process for multi-year procurement to enable the central buyers to efficiently satisfy the local capacity requirements, while providing

[69] PG&E Opening Testimony at 2-6, SDG&E Testimony at 4.

[70] D.07-12-052 at 171.

assurances for cost recovery and minimizing the need for ex post reasonableness review.

Accordingly, the Commission adopts a similar process whereby a procurement action is deemed reasonable and preapproved if the resource procured by the central buyer (1) meets the established local capacity requirements and underlying data supporting those requirements, which are based on the CAISO's LCRTS and adopted annually by Commission decision; (2) if the PRG was properly consulted, as described above; and (3) if procurement was deemed by the IE to have followed all relevant Commission guidance, including least-cost best-fit methodology and other noted selection criteria.

The Commission believes this preapproval process is sufficient to guide the central buyers through the initial local procurement for the 2020 compliance year. However, we recognize that further refinements to the criteria may be necessary and the Commission may refine the process as needed after the first procurement results and IE report have been evaluated.

#### 3.1.9.4. Compliance Reports

In D.02-10-062, which adopted a procurement and cost recovery framework for the investor-owned utilities, the Commission required the utilities to submit quarterly filings for procurement transactions via advice letter.[71] The Commission currently requires each investor-owned utility to submit a Quarterly Compliance Report (QCR) via the advice letter process within 30 days of the end of the quarter. The purpose of the QCR is to allow the Commission to review the procurement transactions for compliance with the approved bundled

[71] D.02-10-062 at Ordering Paragraph 8. This process was later modified in D.03-06-076, D.07-12-062, and D.12-01-062.

procurement plans and the upfront standards and criteria. The QCRs are reviewed by Energy Division and the Commission's Utility Audit, Finance, and Compliance Branch.

The Commission finds it reasonable to adopt a similar compliance showing here, as is currently required of the investor-owned utilities. For the multi-year local RA program, the central buyers shall prepare a compliance filing on an annual basis that includes all contract terms and the criteria and methodology used to select local RA resources. The purpose of the filing is to demonstrate that the central buyers are in compliance with the requirements and objectives adopted in this decision, as well as the adopted annual multi-year RA requirements. The final IE report shall also be filed as part of this annual compliance filing in both confidential and public (redacted) form.

#### 3.1.9.5. Competitive Neutrality Rules

Within the central procurement process, potentially market-sensitive information relates to confidential, competitive information received from generators, LSEs, or third-party marketers in the process of enabling the distribution utility to perform duties necessary to conduct solicitations and procure local resources as part of its central procurement role. The Commission recognizes that this competitive information should be appropriately protected in an effort to address anti-competitive concerns and facilitate confidence and certainty in the central procurement process. Energy Division proposes that the distribution utilities establish an independent procurement arm subject to competitive neutrality rules, as adopted in D.13-12-029. D.13-12-029 adopted competitive neutrality rules applicable to demand response providers' participation in the CAISO's wholesale markets. Of relevance here, that decision adopted the following:

> Rule 24 shall include provisions to protect the confidential, competitive information received from a demand response provider (Provider) or from the [CAISO] about the Provider or its customers, to enable the utility to perform duties necessary to implement and administer the Provider's use of a bundled utility load for direct participation under this Rule in the CAISO market. Such confidential, competitive information received from the Provider or the CAISO may not be used to promote the utility's services to customers. The utility staff receiving such confidential, competitive information from the Provider or CAISO in the discharge of the utility's roles and responsibilities under the Rule shall not share such confidential, competitive information with other individuals in the utility who are also responsible for discharging the utility's roles and responsibilities, as a Demand Response Provider, under Rule 24. (D.13-12-029, Ordering Paragraph 10.)

AReM opposes the use of the competitive neutrality rules as applicable to the central buyer, arguing that these "rules were never intended to address a construct like the Central Buyer and cannot be bootstrapped into that role." (AReM Comments at 6-7.)

While the competitive neutrality rules in D.13-02-029 may have originated under different circumstances, we find that the rules are reasonable and appropriate for use in mitigating anti-competitive and conflict of interest concerns related to the distribution utilities' solicitation process and central procurement of local resources. In order to ensure competitive neutrality and prohibit the sharing of confidential information obtained as part of the central procurement process, the Commission agrees with Energy Division's proposal to require the distribution utilities to be subject to competitive neutrality rules.

Accordingly, the Commission directs each distribution utility to establish a rule or procedure that will govern how confidential, market-sensitive information received by the distribution utility from generators, LSEs, or third-party marketers as part of the central solicitation and procurement process will be protected, as well as what firewall safeguards will be implemented to prevent the sharing of information beyond those employees involved in the central solicitation and procurement process. The distribution utilities shall file and serve their proposed rule into the RA proceeding. Once the proposals are submitted, parties will have an opportunity to comment and the proposals will be addressed in Track 3 of this proceeding.

Additionally, in D.07-12-052, the investor-owned utility, along with the IE, PRG and Energy Division staff, was directed to "develop a strict code of conduct - to be signed by any and all IOU personnel involved in the RFO process – to prevent sharing of sensitive information between staff involved in developing utility bids and staff who created the bid evaluation criteria and select winning bids." (D.07-12-052 at 206.)

In addition to directives on competitive neutrality, the Commission adopts a requirement that the central buyer, in collaboration with the IE, PRG and Energy Division, shall create a strict code of conduct, as similarly adopted in D.07-12-052, that prevents the sharing of market-sensitive information beyond employees involved in the central solicitation and procurement function. Any personnel employed by the distribution utility (including management and officers) who is involved in the solicitation and procurement process shall sign the code of conduct as a precondition to conducting the central solicitation and procurement process. With the adoption of these safeguards, the Commission does not find it necessary for the distribution utilities to establish an independent procurement arm, as proposed by Energy Division, and we decline to adopt such a requirement.

#### 3.1.9.6. Market Power Mitigation

Energy Division states that even with distribution utilities as central buyers, there is a "potential for considerable market power, given that resource procurement will be resources in transmission-constrained local sub-areas, where competition largely does not exist."[72] In order to mitigate this concern, Energy Division proposes that each central buyer "exercise its judgment to decide when it would be better for the resource to be procured through the annual backstop mechanisms, which are limited to one year and capped at the soft offer price of $6.31 kw-month…" (Energy Division Proposal at 18.) SDG&E recommends a price cap (in $/kW-year) be set and if an offer exceeds the price cap, the central entity is not obligated to procure that resource. (SDG&E Testimony at 15.)

Additionally, PG&E proposes that if any local offers raise market power concerns, "the [central buyer] should raise those concerns to the CPUC in its filing, and the [central buyer] shall not procure resources that it reasonably believes is exercising market power. In the case that the resource is needed for local reliability purposes, CAISO may separately procure that resource under its existing tariff for a limited term." (PG&E Reply Testimony at 2-7.)

The Commission supports Energy Division's proposal to give the central buyers discretion to defer procurement of a local resource to the CAISO's backstop mechanisms, rather than through the solicitation process, if bid costs are deemed unreasonably high. The Commission finds this to be a reasonable exercise of discretion particularly in light of the other oversight mechanisms adopted in this decision.

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[72] Energy Division Proposal at 18. *See also* AReM Comments at 5-6, PG&E Testimony at 1-8.

Relatedly, Energy Division proposes that the central buyers should not be assessed penalties for failure to procure resources to meet the local requirements, so long as reasonable attempts are made. (Energy Division Proposal at 18.) If a resource is not procured in the solicitation, it could be procured in the following year's solicitation and if that fails to occur, backstop authority may be used to retain the resource. Energy Division recommends that the Independent Evaluator report on any market power issues that may have caused the failure to procure. (*Id*.) PG&E supports Energy Division's proposal but adds that the IE report should include the reason for the failure. (PG&E Reply Testimony at 1-26.)

The Commission agrees that the central buyers should not be assessed fines or penalties for failing to procure resources to meet the local RA requirements, as long as the central buyers exercise reasonable efforts to secure capacity and the IE report contains the reasons for the failures to procure.

### 3.10. Modifications to RA Timeline

In the Track 1 decision, the Commission directed parties to propose a timeline for full implementation of a multi-year local RA requirement, including necessary preliminary steps and transition or phase-in periods. (D.18-06-030 at 28-29.)

Energy Division favors keeping the RA timeline as is, except to add an additional filing in late-September for the central buyer to file its local showing. (Energy Division Proposal at 16.) Energy Division's proposed timeline for the 2020 compliance year is summarized as follows:

- **February 2019**: Parties file comments on LCR assumptions and inputs in Track 3 of the RA proceeding.

- **April 2019**: The CAISO files draft LCR one- and five-year ahead studies. LCR studies will include any CAISO-approved transmission upgrades from the Transmission Planning Process (TPP) LCR study.
- **June 2019**: The Commission adopts multi-year local RA requirements for the 2020-2022 compliance years as part of its Track 3 decision.
- **July 2019**:
  - LSEs receive initial RA allocations, including CAM credits towards system and flexible requirements (but are not allocated local requirements).
  - Central buyers receive total jurisdictional share of multi-year local RA requirements for 2020-2022 compliance years.
- **July – September 2019:** Central buyers run solicitation for all local areas.
- **Late September 2019:** Central buyers make local RA showing to the Commission and the CAISO. The showing includes any additional attributes procured along with the local RA (*e.g.,* system RA, flexible RA, and dispatch rights).
- **Late September/early October 2019:** LSEs are allocated final CAM credits (based on coincident load shares) for any system and flexible capacity that was procured during the local RA procurement or backstop processes.
- **End of October 2019:** LSEs are still required to make system and flexible RA showing. The CAISO determines necessary backstop procurement.

The CAISO proposes a significant change to the RA timeline that shifts the compliance year to begin on April 1 instead of January 1. The CAISO supports this in part to give resource owners additional time for retirement and maintenance decisions, as well as to allow backstop procurement to occur prior to the first monthly showing of the year. (CAISO Testimony, Chapter 3 at 5.)

CalCCA and Calpine support shifting the RA compliance year to begin in April. (Calpine Comments at 6, CalCCA Testimony at 22.)

Some parties oppose proposals to modify the current RA compliance timeline as unnecessary. SDG&E states that "[s]hifting the RA compliance timeline would require significant modifications to the current RA construct, but would provide limited value." (SDG&E Comments on SCE Proposal at 6-7.)

The Commission does not find sufficient record support to authorize a significant shift in the RA timeline. The current timeline contains multiple inter-dependent events and inputs that occur in parallel. Therefore, shifting the timeline by a few months is a major undertaking that should involve a prudent, thorough review and coordination among multiple agencies. Particularly in light of the many changes to the local RA program adopted in this decision, the Commission deems it appropriate to keep the current start date for the RA compliance year. Accordingly, we adopt Energy Division's proposed timeline in anticipation of the 2020 compliance year and future years.

### 3.11. Expanding Multi-Year Framework to System or Flexible RA

In the Track 1 decision, the Commission concluded that limiting central procurement to local RA resources was appropriate in order to "preserve procurement flexibility for all LSEs and limit program modifications to only the most critical areas." (D.18-06-030 at 32.) The Commission stated that as the flexible RA construct is under evaluation, the Commission did not intend to adopt multi-year system and flexible RA requirements at this time. (*Id*. at 8.)

In Track 2 proposals, several parties support expanding multi-year and/or central procurement to system and flexible requirements, in addition to local requirements.[73] Parties primarily comment that procurement will be needlessly complicated if different RA products are procured at different durations or percentage obligations.

Parties who oppose expanding multi-year procurement beyond local RA argue that the Commission should await evaluation of the multi-year local program before expanding to system and flexible RA.[74] PG&E and AReM assert that the concerns about RA procurement to date primarily affect local RA, such as the use of local waivers, increased use of backstop procurement, and anticipated retirement of local resources.[75] Likewise, SCE cautions that there has been "no clear demonstration that the existing RA program has failed in ensuring adequate System and Flexibility capacity to the grid." (SCE Comments at 12.) PG&E further argues that market power issues inherent in local RA make it uniquely appropriate for central procurement. (PG&E Reply Testimony at 1-22.)

The Commission agrees that the RA procurement issues observed thus far pertain to local RA and therefore, expansion to flexible and system RA is premature and needs to be fully explored. The Commission declines to adopt multi-year requirements for system and flexible RA at this time. However, the Commission agrees that there may be potential benefits to expanding multi-year requirements to system and flexible RA, and will continue to monitor and

[73] *See, e.g.*, Calpine Comments at 5, CAISO Testimony Chapter 2 at 1, Diamond/Sentinel Comments at 2, IEP Testimony at 10, Middle River Testimony at 6, NRG Testimony at 9, WPTF Testimony at 4.

[74] *See, e.g.*, AReM Comments at 23, ORA Comments at 23, PG&E Opening Testimony at 2-17, SCE Comments at 12.

[75] AReM Comments at 21, PG&E Reply Testimony at 1-22.

evaluate the multi-year local RA program to consider expansion to flexible and/or system RA in the future.

### 3.12. Expanding CAISO Backstop Authority

Under the solicitation process adopted in this decision, the central buyers will make their annual local RA showing and any deficiencies will still be subject to the CAISO's backstop procurement, as is currently done in the RA program. The existing backstop mechanisms include the Capacity Procurement Mechanism (CPM) designation and Reliability Must Run (RMR) contracts.

The CAISO states that it will not implement backstop procurement on a multi-year basis in the initial 2020 multi-year procurement cycle. However, the CAISO intends to "conduct its own stakeholder initiative to implement multi-year backstop procurement commencing with the 2021 procurement cycle." (CAISO Comments at 6.)

PG&E, Energy Division, and ORA oppose expanding the backstop mechanisms beyond the annual process. Energy Division believes the CPM process should remain an annual process to incentivize generators to execute multi-year contracts though a bilateral process rather than through backstop mechanisms. (Energy Division Proposal at 18.) Energy Division adds that an annual backstop process is consistent with the purpose of backstop authority which is to provide operational reliability, as compared to the RA program which is intended as a longer-term planning mechanism. (*Id.*) PG&E and ORA state that expanding backstop authority also runs counter to one of the Commission's objectives in this proceeding which is to avoid costly backstop procurement.[76]

[76] ORA Comments at 20, PG&E Reply Testimony at 1-16.

The Commission agrees that the CAISO backstop mechanisms should not be expanded beyond an annual process at this point, as that would interfere with efficient procurement of local RA through the Commission's RA program.

### 3.13. Transparency

In Track 1 of this proceeding, Sierra Club submitted a proposal relating to greater transparency in RA contracting. In the Track 1 decision, we stated that while the Commission supports transparency, "[g]iven the complexity of this issue and the relatively thin record currently before the Commission," it is more appropriate to address transparency proposals in Track 2.

In their Track 2 proposal, the Joint Environmental Parties propose that each December, the LSEs provide certain non-market sensitive information on RA contracts for that year.[77] Energy Division recommends that at the beginning of each year, portions of an LSEs' RA plans from the previous year should be released but that certain information, such as megawatts contracted or contract length, remain confidential to ensure that an LSE's forward position be protected. Energy Division posed several questions in its proposal for further comment by parties. (Energy Division Transparency Proposal at 3-4.) AReM argues that both proposals violate D.06-06-066, which states that LSEs' RA contract information is confidential three-years forward and one-year back. (AReM Comments at 30.)

In response to Energy Division's proposal, PG&E recommends that one way to make information available concerning RA resources in an LSEs'

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[77] Joint Environmental Parties Testimony at 4-6. The information disclosed would include: resource name, technology type, CalEnviroScreen score, megawatts, type of RA contracted, local and sub-local area (if applicable), months contracted for, and duration of contract (if publicly available). Additionally, the LSE would disclose loading order compliance, disadvantaged community impacts, and preferred resources contracting. (*Id.*)

portfolio, in a manner that protects market sensitive information, is to disclose all resources used to satisfy an LSE's RA obligation in the previous year without identifying the number of megawatts associated with the resources. According to PG&E, this would protect market sensitive information such as an LSE's load share and open position while satisfying Sierra Club's request to determine which resources LSEs have contracted with.[78]

The Commission finds that PG&E's recommendation is a reasonable first step to promoting transparency in RA contracting. Accordingly, early each calendar year, we direct Energy Division to post a summary list of the resources listed on each LSE's monthly RA plans for the previous year. As proposed by Energy Division, the information to be shared shall include scheduling resource ID, scheduling coordinator ID or counterparty, zonal location, and local area (if applicable).

## 4. Comments on Proposed Decision

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

[78] PG&E Comments at 2-5 - 2-7.

## 5. Assignment of Proceeding

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

## Findings of Fact

1. The Commission intends to move expeditiously to implement a central buyer mechanism to begin for the 2020 RA compliance year.

2. The distribution utilities are the central buyer candidates with the resources, knowledge and experience to procure local reliability resources on behalf of all LSEs without excessive delay.

3. Critical objectives in developing a multi-year local RA framework include accounting for increased load migration, ensuring necessary resources are procured in an orderly manner, and reducing procurement deficiencies that lead to costly out-of-market RA procurement.

4. A full procurement approach allows the central buyer to secure a portfolio of the most effective local resources, adapt to load uncertainty and migration, and ensure sufficient capacity is procured to meet local needs over a multi-year duration.

5. It is important to adopt a multi-year forward duration that accommodates year-to-year changes in local requirements and provides flexibility for market variabilities in later years that may relieve local constraints.

6. A three-year multi-year forward duration strikes a reasonable balance in accommodating yearly variations in local capacity requirement results and providing flexibility for preferred alternatives to develop and potentially reduce local capacity needs.

7. Reliance on the CAISO's existing Local Capacity Requirement Technical Studies, with the incorporation of new transmission planning assumptions, will minimize over-procurement of local RA after Year 1.

8. It is important to adopt a procurement percentage that accommodates year-to-year changes in local requirements and provides flexibility for market variabilities in later years that may relieve local constraints.

9. A 100% procurement requirement for Years 1 and 2, and an 80% requirement for Year 3 strikes a reasonable balance in accommodating yearly variations in local capacity requirement results and providing flexibility for market variabilities in later years that may relieve local constraints.

10. The Commission seeks a procurement mechanism that allows the central buyers to engage in targeted procurement necessary to address local and sub-local reliability and that is implementable without excessive delay.

11. A competitive solicitation process for local RA procurement provides the central buyer with flexibility to select resources based on targeted criteria and allows for relatively quick implementation.

12. The requirements pertaining to an all-source solicitation process adopted in past Commission decisions, including bidding of new and existing resources, are reasonable and appropriate guidance for the multi-year local RA program.

13. Proposals that state that CAM and local DR resources should reduce the local RA amount procured by the central buyer are reasonable and consistent with the current RA program.

14. Proposals that state that RA attributes should remain bundled and that LSEs should receive credit for procured system or flexible capacity, based on coincident load shares, are reasonable and consistent with the current RA program.

15. It is important for the central buyers to include dispatch rights in their solicitations as an optional term for bidders to include.

16. It is reasonable to treat local DR resources as is currently done in the year-ahead timeframe, based on the applicable three-year period of the most recent load impact protocol studies after any Energy Division adjustments.

17. There is insufficient record support at this time to adopt a proposal to require the central buyers to procure dispatch rights along with the local RA products.

18. Requiring the distribution utilities to bid their own resources into the solicitation at their levelized fixed costs is reasonable.

19. The Commission seeks to adopt a solicitation process that includes quantitative and qualitative criteria that the central buyers can employ in selecting local resources.

20. The least-cost best-fit methodology and other selection criteria adopted in past Commission decisions serve as useful guidance for the selection of local RA resources by the central buyers.

21. The adopted cost recovery mechanism should facilitate the central buyers' efficient procurement of local resources and provide necessary recovery of costs incurred by the central buyers.

22. The CAM methodology is a cost recovery mechanism that allows the central buyers to efficiently procure local resources and provide recovery of costs incurred.

23. The Commission seeks to adopt oversight mechanisms that provide market participants with reasonable assurances as to the neutrality and transparency of the central procurement process, while giving the central buyers necessary flexibility and discretion to efficiently procure local resources.

24. The proposal to use the CAM PRG to advise the central buyers through the solicitation process satisfies the Commission's objectives in adopting procurement oversight mechanisms.

25. Proposals to authorize an independent evaluator to monitor the central buyers' solicitation and contract execution process satisfy the Commission's objectives in adopting procurement oversight mechanisms.

26. The Commission seeks to adopt an approval process that gives the distribution utilities achievable standards for cost recovery, authorizes procurement decisions that incorporate the Commission's policy direction, and eliminates the need for after-the-fact reasonableness review of procurement actions.

27. A portfolio approval process, similar to that adopted in D.07-12-052, satisfies the Commission's objectives for establishing a preapproval process for multi-year procurement.

28. It is important for the central buyers to demonstrate that they are in compliance with the requirements and objectives adopted in this decision, as well as the adopted annual multi-year RA requirements.

29. An annual compliance filing submitted by the central buyers would demonstrate compliance with the requirements and objectives of this decision.

30. To mitigate anti-competitive concerns, the confidential, market-sensitive information received by the distribution utilities from third-party market participants through the solicitation and procurement process must be adequately protected and not shared beyond personnel involved in the central procurement function.

31. A rule to be established by the distribution utilities that governs how confidential, market-sensitive information will be protected would mitigate anti-competitive concerns.

32. A strict code of conduct to be established by the distribution utilities that governs personnel (including management and officers) involved in the central solicitation and procurement process would mitigate anti-competitive concerns.

33. It is reasonable to give the central buyers discretion to defer procurement of a local resource to the CAISO's backstop mechanisms if bid costs are deemed unreasonably high.

34. It is unnecessary to assess penalties or fines on the central buyer for failing to procure resources to meet local RA requirements, as long as the central buyer exercised reasonable efforts to secure capacity.

35. Is it reasonable to maintain the current RA timeline in anticipation of the 2020 compliance year.

36. The Commission supports facilitating transparency in the RA contracting process. A proposal to disclose all resources used to satisfy an LSE's RA obligation in the previous year, without disclosing the number of megawatts associated with the resource, is a reasonable first step towards promoting transparency.

## Conclusions of Law

1. The distribution utilities should be designated as the central buyers of local RA capacity for their respective distribution areas.

2. The central buyer should be required to engage in full procurement of local resources within their respective service areas.

3. A minimum three-year forward requirement should be the required duration adopted for the multi-year local resource adequacy program.

4. The CAISO's existing one- and five-year Local Capacity Requirement Technical Studies, incorporating engineer-managed adjustments for CAISO-approved transmission projects, should continue to form the basis for the local requirements for the multi-year RA program.

5. The minimum percentages required for multi-year local procurement by the central buyers should be 100% for Years 1 and 2 and 80% for Year 3.

6. An all-source, competitive, transparent solicitation process should be used by the central buyers for multi-year local RA procurement.

7. RA attributes should remain bundled throughout the solicitation process and LSEs should receive credits for system or flexible capacity procured during the local RA or backstop processes.

8. CAM resources and local DR resources should reduce the local RA amount that the central buyer must procure.

9. Local DR resources should be counted based on the applicable three-year period of the most recent load impact protocol studies after any Energy Division adjustments.

10. The central buyers should include dispatch rights in their solicitations as an optional term that bidders are encouraged to include.

11. A proposal to require the central buyers to procure dispatch rights along with the local RA products should not be adopted at this time.

12. The distribution utilities should bid their own resources into the solicitation process at their levelized fixed costs.

13. To guide the selection of local resources, the central buyers should evaluate resources using the least-cost best-fit methodology and including the following criteria: (1) future needs in local and sub-local areas, (2) local effectiveness factors, (3) resource costs, (4) operational characteristics of the resources, (5) location of the facility, (6) costs of potential alternatives, and (7) greenhouse gas adders.

14. The CAM methodology should be adopted as the cost recovery mechanism to cover procurement costs associated with serving the central procurement function.

15. The administrative costs incurred by the central buyers in serving the central procurement function should be recoverable under the cost allocation mechanism.

16. The CAM Procurement Review Group should be adopted to advise the central buyers, in consultation with Energy Division and an independent evaluator, through the procurement process.

17. An independent evaluator should be authorized to monitor the central buyers' solicitation process and contract execution process. The central buyers should use the requirements for the IE process adopted in D.04-12-048 as guidance but that process shall represent a minimum standard.

18. A portfolio approval process should be authorized to govern when a procurement action by the central buyer is deemed reasonable and preapproved.

19. The central buyers should submit an annual compliance filing that includes all contract terms, as well as the criteria and methodology used to select local RA resources.

20. The distribution utilities should establish a rule that will govern how confidential, market-sensitive information will be protected to prevent the sharing of information outside of personnel involved in the central solicitation and procurement function. The distribution utilities should file and serve the proposed rule into the RA proceeding where parties will have an opportunity to comment.

21. The distribution utilities should establish a strict code of conduct that governs the sharing of sensitive information beyond personnel involved in the central solicitation and procurement function (including management and officers).

22. The central buyers should have discretion to defer procurement of a local resource to the CAISO's backstop mechanisms if bid costs are deemed unreasonably high.

23. The central buyer should not be assessed fines or penalties for failing to procure resources, as long as the central buyer made reasonable efforts to secure capacity.

24. Energy Division's proposed timeline in anticipation of the 2020 compliance year and future years should be adopted.

25. Early each calendar year, Energy Division should post a summary list of the resources listed on each LSE's monthly resource adequacy plans for the previous year.

## O R D E R

IT IS ORDERED that:

1. The distribution utilities (Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company) shall serve as the central buyers for their respective distribution service areas for the multi-year local resource adequacy program.

2. The central buyer shall engage in full procurement of local resources within their respective distribution service areas.

3. A minimum three-year forward duration shall be the required duration adopted for the multi-year local resource adequacy program.

4. The California Independent System Operator's (CAISO) existing one- and five-year ahead study, with the requirement to incorporate engineer-managed adjustments for CAISO-approved transmission projects scheduled for that year, shall form the basis for the local resource adequacy requirements. The inputs and assumptions used for the CAISO's Local Capacity Requirements Technical Studies shall be filed in the resource adequacy proceeding.

5. The California Independent System Operator's existing one-year ahead study shall form the basis for the local requirements for Years 1 and 2. The existing five-year study shall inform the local requirements for Year 3.

6. The minimum required percentage for procurement by the central buyer in Years 1 and 2 shall be a 100% requirement. The minimum required percentage for procurement in Year 3 shall be 80%.

7. The central buyers shall conduct a transparent, competitive, all-source solicitation for multi-year local resource adequacy (RA) procurement with the following requirements:

(a) Any existing local resource that does not have a contract, any new local resource that can be brought online in time to meet solicitation requirements, or any load serving entity (LSE) or third-party with an existing local RA contract may bid into the solicitation.

(b) If an LSE-procured local resource is not selected by the central buyer, the local resource may still count towards the LSE's system or flexible RA obligations, if applicable.

(c) RA attributes shall remain bundled and LSEs shall receive credits for any system or flexible capacity procured during the local RA or backstop processes, based on coincident load shares, as is currently done with Cost Allocation Mechanism (CAM) resources.

(d) CAM resources and local Demand Response (DR) resources shall reduce the local RA amount that the central buyer must procure.

(e) The distribution utilities shall bid their own resources into the solicitation process at their levelized fixed costs.

(f) The central buyers shall include dispatch rights in their solicitations as an optional term that bidders are encouraged to include.

8. Local Demand Response (DR) resources shall be counted based on the applicable three-year period of the most recent load impact protocol studies after any Energy Division adjustments, as is the current practice for determining the qualifying capacity value of DR resources on a one-year ahead timeframe.

9. A proposal to require the central buyers to procure dispatch rights along with the local resource adequacy (RA) products is not adopted at this time. The central buyers are strongly encouraged to procure dispatch rights along with the RA capacity whenever doing so is in the financial interest of all ratepayers.

10. To guide the selection of local resources by the central buyers, the central buyers shall evaluate resources using the least-cost best-fit methodology, as

adopted in Decision 04-07-029. The least-cost best-fit methodology employed shall include the following selection criteria:

(a) Future needs in local and sub-local areas;

(b) Local effectiveness factors, as published in the California Independent System Operator's Local Capacity Requirement Technical Studies;

(c) Resource costs;

(d) Operational characteristics of the resources (efficiency, age, flexibility, facility type);

(e) Location of the facility (with consideration for environmental justice);

(f) Costs of potential alternatives; and

(g) Greenhouse Gas adders.

11. The Cost Allocation Mechanism methodology shall be the cost recovery mechanism used to cover the procurement costs incurred in serving the central procurement function. The administrative costs incurred in serving the central procurement function shall be recoverable under the cost allocation mechanism.

12. The central buyers shall establish a balancing account to facilitate the cost recovery process.

13. The Cost Allocation Mechanism (CAM) Procurement Review Group (PRG), as adopted in Decision 07-12-052, shall be authorized to advise the central buyers. The central buyers shall consult with CAM PRG members (including Energy Division and an independent evaluator) to outline procurement plans, draft solicitation bid documents, and collect feedback regarding the solicitation process.

14. An independent evaluator (IE) shall be authorized to monitor the central buyers' solicitation process and contract execution process, as follows:

(a) The central buyers shall collectively develop a pool of at least three IEs, with the appropriate level of technical expertise and experience, to serve on a rotating basis for solicitations. Energy Division will have final approval over the selection of the IEs.

(b) The IE shall prepare a report to be submitted on an annual basis to the Commission, assessing the neutrality of the procurement process, market power or aggregate pricing concerns, and other relevant issues.

(c) The IE shall brief the Procurement Review Group (PRG) in meetings on the procurement process and concerns related to neutrality, market power, pricing, disadvantaged communities, or other relevant concerns.

(d) The central buyers shall permit periodic oversight of the IE process by Energy Division.

(e) The IE shall brief the PRG on key solicitation elements.

(f) The central buyers shall rely on the requirements for the IE process adopted in Decision 04-12-048 as guidance; however, such guidance shall represent a minimum standard for the IE process.

15. A portfolio approval process shall be adopted in a later phase of this proceeding whereby a procurement action shall be deemed reasonable and preapproved if the following conditions are met:

(a) The procured resource meets the established local capacity requirements and underlying data supporting those requirements, which are based on the California Independent System Operator's Local Capacity Requirements Technical Studies;

(b) If the Procurement Review Group was properly consulted, as described in Ordering Paragraph 13; and

(c) If procurement was deemed by the Independent Evaluator to have followed all relevant Commission guidance, including least-cost best-fit methodology and other noted selection criteria.

16. An annual compliance filing shall be submitted by the central buyers that includes all contract terms, as well as the criteria and methodology used to select local resource adequacy resources. The final Independent Evaluator report shall be filed with the annual compliance filing in both confidential and public (redacted) form.

17. The distribution utilities shall establish a rule or procedure that will govern how confidential, market-sensitive information received from third-party market participants during the solicitation process will be protected and what firewall safeguards will be implemented to prevent the sharing of information beyond those employees involved in the solicitation and procurement process. The distribution utilities shall file and serve the proposed rule into the resource adequacy proceeding and parties shall have an opportunity to comment in Track 3.

18. The central buyers, in collaboration with the Independent Evaluator, Procurement Review Group, and Energy Division, shall create a strict code of conduct, similar to that adopted in Decision 07-12-052, that prevents the sharing of confidential, market-sensitive information beyond those employees involved in the solicitation and procurement process. Personnel employed by the central buyer and involved in the solicitation and procurement process (including management and officers) shall sign the code of conduct as a precondition to engaging in the central solicitation and procurement process.

19. The central buyers shall have discretion to defer procurement of a local resource to the California Independent System Operator's backstop mechanisms, rather than through the solicitation process, if bid costs are deemed unreasonably high.

20. The central buyers shall not be assessed fines or penalties for failing to procure resources to meet the local resource adequacy requirements, as long as the central buyers exercise reasonable efforts to secure capacity and the Independent Evaluator report contains the reasons for the failure to procure.

21. Energy Division's proposed timeline in anticipation of the 2020 compliance year and future years shall be adopted.

22. Early each calendar year, Energy Division shall post a summary list of the resources listed on each LSE's monthly resource adequacy plans for the previous year. The disclosed information shall include scheduling resource ID, scheduling coordinator ID or counterparty, zonal location, and local area (if applicable).

23. This proceeding remains open.

This order is effective today.

Dated ____________________, at San Francisco, California.