STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

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

FILED
05-22-12
02:27 PM

May 22, 2012

Agenda ID #11359
Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 11-10-023

This is the proposed decision of Administrative Law Judge (ALJ) David M. Gamson. It will not appear on the Commission's agenda sooner than 30 days from the date it is mailed. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 15 pages.

Comments must be filed pursuant to Rule 1.13 either electronically or in hard copy. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJ David M. Gamson at dmg@cpuc.ca.gov and the assigned Commissioner. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ KAREN V. CLOPTON
Karen V. Clopton, Chief
Administrative Law Judge

KVC:sbf

Attachment

Decision **PROPOSED DECISION OF ALJ GAMSON** (Mailed 5/22/2012)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations.	Rulemaking 11-10-023 (Filed October 20, 2011)

DECISION ADOPTING LOCAL PROCUREMENT OBLIGATIONS FOR 2013 AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

TABLE OF CONTENTS

Title **Page**

DECISION ADOPTING LOCAL PROCUREMENT OBLIGATIONS FOR 2013 AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

1. Summary

This decision establishes local capacity procurement obligations for 2013 applicable to Commission-jurisdictional electric load-serving entities. These procurement obligations are based on an annual study of local capacity requirements performed by the California Independent System Operator (ISO) for 2013. The total local capacity requirements determined by the ISO for all local areas combined decreased slightly from the prior year; the decrease is from 26,788 megawatts (MW) in 2012 to 25, 769 MW in 2013. The existing capacity needed decreased from 26,158 MW in 2012 to 25,189 in 2013.

In this decision, we consider proposals by the ISO and the Energy Division to address flexible capacity needs with regard to local capacity requirements over the next several years. We agree that there are good reasons to define "flexibility" for Resource Adequacy purposes and identify the types of flexible resources needed to maintain reliability. While both proposals have appealing elements and move toward potential solutions, parties are largely in consensus that neither proposal is sufficiently detailed and ready for implementation at this time. As the ISO and parties agree, there is no compelling need to resolve this issue for the 2013 Resource Adequacy year; however, the ISO seeks resolution well ahead of 2014. Therefore, we will study flexible capacity proposals further in this proceeding, and intend to issue a decision by or near the end of 2012 on this topic. We will coordinate our efforts in this proceeding with efforts in the Long-Term Procurement Process proceeding (Rulemaking 12-03-014) to provide a method for contracting for multi-year local capacity needs.

In addition, this decision modifies the Resource Adequacy program to adopt a different calculation for the coincidence adjustment factor, in order to more accurately reflect cost causation, and continues certain Resource Adequacy exemptions for Pacific Gas and Electric Company's demand response programs for 2013.

2. Background

Public Utilities Code Section 380 (as amended by Stats. 2008, ch. 558, Sec. 13, effective January 1, 2009) requires that "the Commission, in consultation with the California Independent System Operator, shall establish resource adequacy requirements for all load-serving entities." The statute establishes a number of objectives for the Commission to achieve with the program, including development of new generating capacity and retention of existing generating capacity, equitable allocation of the cost of generating capacity, and minimization of enforcement requirements and costs. Section 380 (j) defines "load-serving entities" for purposes of this section as "an electrical corporation, electric service provider, or community choice aggregator."

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

This proceeding has been divided into two phases. Phase One considers local capacity procurement obligations for 2013 applicable to Commission-jurisdictional electric LSEs and several proposed RA program refinements. Phase Two will consider local capacity procurement obligations for

2014 applicable to Commission-jurisdictional electric LSEs and any further RA program refinements.

An *Assigned Commissioner's Ruling and Scoping Memo* (Scoping Memo), issued on December 27, 2011, identified the issues to be considered in Phase One of this proceeding as well as the procedure and schedule for their consideration. Two broad categories of issues were established. The first category, local RA issues, pertains to the California Independent System Operator's (ISO) 2013 local capacity requirements (LCR) study as well as this Commission's establishment of local procurement obligations for 2013 based on the LCR study. The second category, program refinement issues, pertains to various proposals to modify the RA program.

The Scoping Ruling identified the following issues for this proceeding:

1. Review the yearly LCR recommended by the ISO;
2. Refinements to the RA program:
   a. Standard Capacity Product (SCP) implementation for demand response resources;
   b. A reevaluation of the Maximum Cumulative Capacity (MCC) buckets to include demand response resources as a supply resource, as well as other policy and implementation improvements to the MCC construct;
   c. Adjustments to the RA coincidence adjustments;
   d. Development of qualifying capacity (QC) rules for dynamically scheduled and pseudo-tie resources;
   e. Allocation of RA credit for third-party demand response providers who participate in Reliability demand response programs;
   f. Recommendations from the ISO regarding the type of resources needed to manage the grid, and how to provide such resources to the ISO within the RA program;

g. Update RA rules to account for differences in procurement due to the 33% Renewable Portfolio Standard requirement, the electrical system's operational needs, and related issues;

h. Staff implementation proposals, including:

- QC rules for dynamically scheduled or pseudo tie resources;
- Revisions to the MCC bucket percentages and some policy changes to refine and clarify additional policies; and
- Changes to the rounding convention as adopted in Decision (D.) 07-06-029.

The Commission's Energy Division facilitated workshops on RA program refinement issues[1] on January 26 and 27, 2012, summaries of which were transcribed and are on the record. Not all of the issues in the Scoping Memo were developed sufficiently to resolve in this decision. Those issues not resolved herein remain in the scope of the proceeding, subject to further scoping by the assigned Commissioner. On March 2, 2012, the ISO filed a supplement to its proposal regarding flexible capacity from the January workshops.

An Administrative Law Judge's (ALJ's) Ruling on March 23, 2012 provided that parties may comment on an attached Energy Division workshop report and all topics addressed in presentations and/or in the transcripts of the January workshops, and on the ISO supplemental proposal. Comments on the Phase One issues discussed in the workshops were filed on April 11, 2012 by Abengoa Solar, Inc. (Abengoa); Alliance for Retail Energy Markets (AReM); Brookfield Renewable Energy Partners LP (Brookfield); Calpine Corporation

[1] Excluding the 2013 local capacity requirements.

(Calpine); the ISO; California Energy Storage Alliance (CESA); California Large Energy Consumers Association (CLECA), Center for Energy Efficiency and Renewable Technologies (CEERT); Cogeneration Association of California (CAC); Division of Ratepayer Advocates (DRA); GenOn California North LLC and GenOn Delta LLC (GenOn); EnerNOC, Inc. (EnerNOC); Interstate Renewable Energy Council, Inc. (IREC); NRG Energy, Inc. (NRG); Pacific Gas and Electric Company (PG&E); Shell Energy North America (US), L.P. (Shell); Southern California Edison Company (SCE); San Diego Gas & Electric Company (SDG&E); and The Utility Reform Network (TURN). EnerNOC; The ISO; California Wind Energy Association (CalWEA); DRA; IREC; NRG; PG&E; SCE; SDG&E; Shell; The Vote Solar Initiative; and TURN filed replies on April 20, 2012.

3. Local RA for 2013

3.1. 2013 Local Capacity Requirements Study

D.06-06-064 determined that a study of LCR performed by the ISO would form the basis for this Commission's local RA program. The ISO conducts its LCR study annually, and this Commission resets local procurement obligations each year based on the ISO's LCR determinations. Following a stakeholder process, the ISO posted its "2013 Local Capacity Technical Analysis, Final Report and Study Results" (2013 LCR Study) on its website, served notice of the report's availability, and filed it with the Commission on May 2, 2012. Comments were filed on May 7, 2012 and replies on May 14, 2012 by TURN and SDG&E.

The ISO states that the assumptions, processes, and criteria used for the 2013 LCR study were discussed and recommended in a stakeholder meeting, and that, on balance, they mirror those used in the 2007 through 2012 LCR studies. The ISO identified and studied capacity needs for the same ten local areas as in previous studies: Humboldt, North Coast/North Bay, Sierra, Greater Bay, Greater Fresno, Big Creek/Ventura, Los Angeles Basin, Stockton, Kern, and San Diego. The ISO notes that its studies assume that the San Onofre Nuclear Generating Station will be fully operational in 2013. However, this plant has been on an extended forced outage this year and the expected date that it will return is unknown. The ISO states that it will continue to monitor the status of this plant and, if needed, will reassess the 2013 LCR values.

D.06-06-064 determined that the reliability level associated with Option 2 as defined in the 2007 LCR study should be applied as the basis for local procurement obligations for that year. The Commission stated that "[w]hile we expect to apply Option 2 in future years in the absence of compelling information demonstrating that the risks of a lesser reliability level can reasonably be assumed, we nevertheless leave for further consideration in this proceeding the appropriate reliability level for Local [resource adequacy requirements] for 2008 and beyond." (D.06-06-064 at 21.) Each of the RA LCR decisions in the last four years adopted Option 2 as recommended by the ISO for 2008 through 2012 local procurement obligations. There is no evidence or recommendation before us suggesting that assumption of the reduced reliability associated with Option 1 is reasonable for 2013. We therefore affirm the continued application of Option 2 to establish local procurement obligations for 2013.

The 2012 and 2013 summary tables in the 2013 LCR report, copied below, show that for all ten areas combined, the total LCR associated with reliability Category C decreased by over 1000 megawatts (MW) (or about 4%) from 26,788 MW in 2012 to 25,769 MW. The existing capacity needed decreased from 26,158 MW in 2012 to 25,189 in 2013. The LCR needs have decreased in the following areas: Sierra, Fresno and LA Basin due to downward trend for load, and Big Creek/Ventura due to downward trend for load, new transmission projects and load allocation change among substations. The LCR needs are steady in Humboldt and Stockton. The LCR needs have slightly increased in North Coast/North Bay, Bay Area and Kern due to load growth; San Diego due to load growth as well as deficiency increase in two small sub-areas.

2013 Local Capacity Requirements

	Qualifying Capacity			2013 LCR Need Based on Category B			2013 LCR Need Based on Category C with Operating Procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	55	162	217	143	0	**143**	190	22*	**212**
North Coast / North Bay	130	739	869	629	0	**629**	629	0	**629**
Sierra	1274	765	2039	1408	0	**1408**	1712	218*	**1930**
Stockton	216	404	620	242	0	**242**	413	154*	**567**
Greater Bay	1368	6296	7664	3479	0	**3479**	4502	0	**4502**
Greater Fresno	314	2503	2817	1786	0	**1786**	1786	0	**1786**
Kern	684	0	684	295	0	**295**	483	42*	**525**
LA Basin	4452	8675	13127	10295	0	**10295**	10295	0	**10295**
Big Creek/ Ventura	1179	4097	5276	2161	0	**2161**	2241	0	**2241**
San Diego	158	3991	4149	2938	0	**2938**	2938	144*	**3082**
Total	**9830**	**27632**	**37462**	**23376**	**0**	**23376**	**25189**	**580**	**25769**

2012 Local Capacity Requirements

	Qualifying Capacity			2012 LCR Need Based on Category B			2012 LCR Need Based on Category C with Operating Procedure		
Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	54	168	222	159	0	**159**	190	22*	**212**
North Coast / North Bay	131	728	859	613	0	**613**	613	0	**613**
Sierra	1277	760	2037	1489	36*	**1525**	1685	289*	**1974**
Stockton	246	259	505	145	0	**145**	389	178*	**567**
Greater Bay	1312	5276	6588	3647	0	**3647**	4278	0	**4278**
Greater Fresno	356	2414	2770	1873	0	**1873**	1899	8*	**1907**
Kern	602	9	611	180	0	**180**	297	28*	**325**
LA Basin	4029	8054	12083	10865	0	**10865**	10865	0	**10865**
Big Creek/ Ventura	1191	4041	5232	3093	0	**3093**	3093	0	**3093**
San Diego	162	2925	3087	2849	0	**2849**	2849	95*	**2944**
Total	**9360**	**24634**	**33994**	**24913**	**36**	**24949**	**26158**	**620**	**26778**

* CAISO note: No local area is "overall deficient." Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

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

The comments reveal no disagreement with the ISO's LCR determinations for 2013 except with regards the San Diego subarea. As Local RA obligations are not set relative to subareas, we do not address this topic here. SDG&E supports the LCR study for the Greater San Diego-IV areas. As we noted in D.11-06-022 and in previous years, it appears that past efforts towards greater transparency and opportunity for participation in the LCR study process have paid off in significant part. We determine that the ISO's final 2013 LCR study should be approved as the basis for establishing local procurement obligations for 2013 applicable to Commission-jurisdictional LSEs.

3.2. Refinements to the Resource Adequacy Program

3.2.1. Continuation of the Local RA Program

The RA program includes both "system" and "local" RA requirements. Each LSE must procure sufficient RA capacity resources to meet both obligations. "System" RA requirements are calculated based on an LSE's peak load plus a 15% planning reserve margin. "Local" RA requirements are calculated based on the ISO's Local Capacity Technical Analysis, and are allocated to each individual Commission-jurisdictional LSE by the Commission. Each LSE must then procure sufficient RA capacity resources in each Local Area to meet their obligation.

D.06-06-064 adopted a framework for local RA and established local procurement obligations for 2007 only. D.07-06-029, D.08-06-031, D.09-06-028, D.10-06-036 and D.11-06-022 established local procurement obligations for 2008, 2009, 2010, 2011 and 2012, respectively. We intend that the local RA program and associated regulatory requirements adopted in those decisions shall be continued in effect for 2013 and thereafter until changed, subject to the 2013 LCRs and procurement obligations adopted by this decision.

In previous decisions, we delegated ministerial aspects of RA program administration to the Commission's Energy Division. Once again, Energy Division should implement the local RA program for 2013 in accordance with the adopted policies.

In the following sections, we discuss issues which were both in the scope of Phase One of the proceeding and developed sufficiently in the record to allow us to make a decision today. Issues in the scope of Phase One not discussed herein may be subsequently considered in another decision in Phase Two of this proceeding.

3.2.2. Flexible Capacity and Maximum Cumulative Capacity Buckets Proposals

The RA proceedings to date have focused upon providing for local reliability needs for the upcoming compliance year, in order to ensure that the Commission's efforts to ensure reliable grid operation succeed. To that end, we adopt local capacity requirements each year with technical input from the ISO. For example, in this year's decision we adopt local capacity requirements for 2013. The RA proceedings have also been a forum to refine the RA program; for example, in past years the RA proceeding has improved ways of determining which and how resources count for local reliability purposes or to provide a penalty system for non-compliance with RA requirements.

In consultation with the ISO and with other stakeholders, we recognize that there may be a need for more specificity in procurement for RA purposes. We can accomplish this through defining "flexibility", so that LSEs can procure resources to meet RA needs in ways which more precisely meet changing reliability needs. Reliability needs are changing over time because of a number of factors. First, recent State Water Resources Control Board rules may now require once-through cooling (OTC) plants to shut down or significantly change their operations before the previously-expected retirement dates for these plans. This rule change necessitates contracting for resources to replace potential lost capacity in the local areas, which are presently dependent on these plants for local reliability. Per the ISO, this is particularly true in the Los Angeles Basin, Big Creek/Ventura, and San Diego areas. Second, the increased flexibility requirements due to the state's 33% Renewable Portfolio Standard might change the reliability characteristics of the grid over the next several years. Some renewable resources have different operating characteristics than many traditional non-fossil based resources – for example, wind or solar resources are typically more intermittent in nature and subsequently they have less operational predictability and flexibility than gas-fired power plants. Going forward, we expect that our continued standard of high reliability of the grid is dependent upon a more complex and flexible fleet of generating resources. Third, there have been changes in load characteristics with changes to peak, shoulder and mid-peak times such that increased supply flexibility (as well as tools such as demand response) is needed.

The ISO raises the issue of the need for flexible capacity to maintain grid reliability over a number of years. The ISO contends that without multi-year capacity contracts, existing flexible resources may not receive sufficient revenues from the energy and ancillary service markets to remain economically viable. They further contend that there is an operational need for the flexibility conventional resources provide, especially during critical ramping periods. Therefore, the ISO seeks modifications to the Commission's programs to ensure that these flexible resources remain economically viable and available to them in order to maintain system reliability, in order to minimize the need for procurement through the ISO backstop procurement mechanism. The ISO also states that if retirement of all planned OTC resources were to occur, insufficient flexibility will occur potentially as early as 2018.

Taken together, these developments mean that there may be a need for additional capacity to meet reliability needs. Because this proceeding concerns capacity needs for one year in the future, but it can take several years to plan and build new generation, the ISO calls for both multi-year contracts for RA resources and a definition of flexible capacity. The Scoping Memo of the current LTPP proceeding, Rulemaking (R.) 12-03-014, commits to consider new rules for procurement of multi-year flexible capacity for local reliability purposes, in coordination with Commission decisions on flexible capacity in this RA proceeding. The LTPP Scoping Memo also foresees an LTPP decision at or near the end of 2012 that may authorize or require Commission-jursidictional Investor-Owned Utilities and/or other LSEs to contract for multi-year local reliability needs to the extent that the Commission finds there is such a need.

Therefore, in this proceeding, we will focus on defining which flexible attributes can or should be included for RA resources one year out. These flexible attributes may also be appropriate for any multi-year local capacity procurement that may be authorized in the LTPP proceeding.

The ISO and Energy Division have each presented a proposal in the record to address the changing flexible attribute needs for local reliability.

<u>The Energy Division Maximum Cumulative Capacity Buckets Proposal</u>

The RA program guides resource procurement by requiring that LSEs procure capacity so that it is available to the ISO when and where needed. During the development of the RA program in 2004 and 2005, concerns surfaced that LSEs might meet their RA obligations by procuring a large number of resources that were either contractually or operationally limited. This would have had an adverse impact on the reliability of the ISO's grid operations. To ensure that LSEs restricted their dependence on limited availability contracts, Energy Division, pursuant to the directives in D.05-10-042, created four resource categories known as the MCC buckets based on the hours of contractual availability. The RA Program now imposes procurement caps in the form of maximum percentage limits on resources procured that fall within each bucket.

Ordering Paragraph 1(b) of D.11-10-003 stated: "A new Maximum Cumulative Capacity bucket is created for demand response resources, subject to the parameters of the bucket to be determined by the Commission for the 2013 Resource Adequacy year." In the event that neither the Energy Division's proposal to redefine the bucket concept nor the ISO's flexible capacity proposal would be adopted, Energy Division proposed to update the load data that made up the buckets in the existing policy framework and to add a bucket for Demand Response explicitly designed to allow Demand Response resources to contribute to RA as supply side resources. Energy Division staff presented these redefined buckets during RA workshops in January as the default proposal.[2]

In the Scoping Memo, Energy Division was directed to prepare and issue a staff proposal to improve implementation of the RA Program by revising the MCC bucket percentages. The current MCC buckets were last evaluated in 2005, using data from 2003 through 2005. Load shapes have changed since then, necessitating a review of the percentages that have been used to determine the amount of resources that the LSEs could procure in each bucket. Energy Division presented a proposal at the January 26-27, 2012 Resource Adequacy workshop, followed by a revised version at the March 30, 2012 workshop. Parties have had the opportunity to comment on both versions.

Energy Division proposes to redefine the MCC buckets to reflect the changing composition of the resource mix by defining MCC buckets based on contractual hours of operation and dispatchability. Dispatchability is defined based on contractual requirements for ISO dispatch, minimum ramp rate, as well

---

[2] Reference to the ED proposal slides for Jan RA workshops.

as ability of the resource to start and ramp to minimum load between the close of the day-ahead market and the start of the next day. Therefore, the new MCC buckets are distinguishable from each other by being dispatchable or non-dispatchable and operate for unlimited hours or restricted hours. Unlimited hours refer to the capability of a resource to run for predictable continuous hours and not strictly for every hour in the day. Based on these characteristics, generation will be assigned to one of the four buckets.

This proposal specifically highlights that standard energy contracts no longer comprise the majority of the RA fleet, since most of the contracts have expired. The changing conditions in the ISO balancing authority area make dispatchability more important for maintaining grid reliability. The current bucket structure and the proposed bucket structure are highlighted in the table below.

	Current Bucket Structure			**Proposed Bucket Structure**		
Bucket Name	Monthly hours of operation	Maximum cumulative percentage of resources	Operational Characteristics	Hours of operation	Maximum percentage of resources	Operational Characteristics
Bucket 4	All hours	100%	None	All hours	100%	Dispatchable
Bucket 3	415	30.1%	None	All hours	69%	Non-dispatchable
Bucket 2	171	18.6%	None	Limited hours	45%	Dispatchable
Bucket 1	87	13.6%	None	Limited hours	5%	Non-dispatchable

<u>The ISO Flexible Capacity Procurement Proposal</u>

The ISO submitted a proposal related to flexible capacity procurement at the January 26-27, 2012 RA workshop, with a revised version filed on March 2, 2012. The ISO presented another version of the proposal at the March 30, 2012 workshop, which it outlined in its April 11, 2012 reply comments.

In its comments the ISO contends that increasing renewable energy generation will displace conventional flexible generation, thus putting conventional resources at risk of retirement. The ISO explains that without RA contracts, existing flexible resources may not receive sufficient revenues from the energy and ancillary service markets to remain economically viable. The ISO asserts that there is a real operational need for the flexibility conventional resources provide, especially during critical ramping periods and thus, the RA program must ensure that these flexible resources remain economically viable and available to the ISO to maintain system reliability and to minimize the need for procurement through the ISO backstop procurement mechanism. The ISO also states that if retirement of all planned OTC resources were to occur, insufficient flexibility will occur potentially as early as 2018.

The ISO proposes that the Commission adopt three new categories of flexible capacity in the RA proceeding: regulation, load following capability, and maximum ramping. Regulation is the capability of a generating unit to respond to four-second signals from the ISO to adjust its output to balance the system. Load following capability is the capability of generating units to respond to the ISO's five-minute dispatch instructions to balance load and generation. Maximum ramping needs reflect the flexibility needs to ensure the longest continuous net load ramp can be achieved by the fleet.

As noted by several parties in comments, more discussion is required to translate these three proposed flexible capacity categories into an explicit RA requirement and load-serving entity procurement terms. To that end, the ISO is no longer requesting that the Commission impose a mandatory flexible capacity requirement for the 2013 compliance year. Instead, the ISO is asking the Commission to adopt the ISO's three flexible capacity categories as a framework for 2013, including the methodology for how the three flexible capacity categories are calculated. With this framework in place as advisory targets in 2013, the ISO recommends a separate phase of the RA proceeding (or a new Rulemaking) to study and further refine how to integrate a flexible capacity requirement into the resource adequacy program for 2014 compliance.

Discussion

No party disputes that grid operations and reliability may suffer without sufficient generation capable of being flexibly dispatched. We agree that we need to define flexible attributes for local reliability purposes in order to ensure ongoing reliability in a changing load and supply environment. Both the ISO and Energy Division have presented worthwhile proposals intended to address, from different perspectives, the need for flexible capacity on the grid in order for the ISO to continue to operate the grid reliably as increasing levels of generation from renewable, often intermittent, sources of power are operational and generating electricity. We appreciate that both proposals involve a significant effort to proactively address the potential for reliability concerns in the coming years. We agree with parties that additional effort is needed, and we thank the parties for their efforts to refine these proposals and identify questions to be answered before they can be implemented.

Although the objectives of both proposals are similar, there are significant differences in the approach proposed by the ISO and Energy Division. The following chart summarizes the major differences in approach:

Comparison of ISO and Energy Division Proposals

	ISO	Energy Division
General Concept	seeks active procurement of flexible resources	limits procurement of non-flexible resources by LSEs by imposing caps.
Definition of Eligibility	categorizes resources based on qualitative class (base load, intermittent etc.)	categorizes eligible units based on operational characteristics (ramp rate, startup time etc.)
Compliance Metric	quantifies amount of flexibility a resource can provide by computing Maximum Continuous Ramping and Load Following, which varies every month,	relies on net qualifying capacity (NQC) values
Definition of Flexibility	a bundle of characteristics, which varies, based on the needs the grid is trying to manage at a particular interval	defines "flexibility" uniformly for all intervals with quantitative metrics.
Procurement Requirements	defines procurement requirements based on extreme cases from actual operating history	defines procurement requirements based on analysis of "typical" or "expected" needs based on actual historical events

Many of the active parties commented on either or both of the ISO and Energy Division proposals. In general, while many parties praised both proposals for their significant efforts to address changing local reliability needs, nearly all parties found one or both proposals to be incomplete. Some parties recommend tentative steps to move forward with one or the other proposal. For example, GenOn recommends adopting the ISO proposal with modifications, but not the Energy Division proposal. Center for Energy Efficiency and Renewable

Technology supports the Energy Division proposal subject to ISO revision. DRA recommends adoption of the Energy Division proposal for a trial in 2013. However, many parties called for the Commission to not adopt either proposal at this time.

Parties raised several concerns about the Energy Division proposal. PG&E contends that the proposal lacked a clear methodology to determine the size of the buckets, or to determine how these buckets should change in the future as more intermittent generation is added to the system. The ISO argues that the Energy Division's approach of limiting the amount of non-flexible resources does not ensure provision of sufficient flexible resources and could also lead to a portfolio of RA resources that is not as durable as the fleet becomes more variable. The ISO further asserts that a significant deficiency in the Energy Division's proposal is that it does not adequately address intra-hour variability or capture the very short term changes in wind and solar generation.

Parties also raised a number of concerns about the ISO proposal. NRG argues that certain aspects of the ISO's proposal warrants further clarification, discussion and refinement, such as whether hydro resources are dispatchable, and whether resources that provide flexibility can be self-scheduled in the ISO's markets. SCE contends that the ISO has not defined how much of a particular attribute each resource would count for and thus how much capacity a generator has to sell and this aspect had to be transparent if the ISO's proposal is going to be commercially viable. In reply comments, the ISO concedes that more discussion is required to translate these flexible categories into procurement requirements.

We agree with Energy Division, the ISO and all parties that there is no immediate need to impose flexibility requirements in 2013. However, we must take steps to ensure that the grid has sufficient flexible resources in the future. TURN echoes the sentiments of most parties in its comments: "(t)he Commission can reasonably defer implementing any flexible capacity requirement beyond the 2013 RA compliance year. However…the Commission should begin addressing possible flexible capacity needs and policies in the very near future with the goal of assessing if such requirements should be imposed for the 2014 RA compliance year."

We will immediately begin the effort to finalize a framework for filling flexible capacity needs in this proceeding. Our intent is to adopt a framework by or near the end of 2012, for implementation in the 2014 RA compliance year. We will also coordinate our efforts in this proceeding with those in the LTPP proceeding. The Scoping Memo in the LTPP proceeding foresees a Commission decision by or near the end of 2012 allowing or requiring utilities and/or other LSEs to procure for local reliability needs under multi-year contracts. The flexible needs framework we expect to adopt in this proceeding could potentially be used for subsequent Request for Offers to fulfill procurement determined in the LTPP proceeding.

At this time, we will provide direction to allow parties to build upon the efforts to date of the ISO and the Energy Division. We agree with SCE's comments on this point: "For a structure to remain commercially viable, we should strive to find the simplest definition of 'flexibility' possible that will provide the CAISO a reliable grid." SCE continues: "Otherwise, we risk making capacity procurement unnecessarily difficult and costly, and the marginal reliability benefits of a complex vs. simple definition of 'flexibility' will be too expensive to rationally justify."

With the goal of ensuring reliability without undue complexity in mind, parties should work towards clearly defining flexibility in terms of specific operational characteristics of generators that the Commission should consider when authorizing new generation. Specifically, parties should consider:

- whether flexibility should be defined variably in intervals or if a consistent definition is more appropriate;
- whether flexibility should be based on essential key characteristics or if a broad definition better serves the purpose; and
- whether flexibility should be defined as a choice between operational characteristics such as magnitude of need, speed of response and contractual availability.

The ALJ and/or assigned Commissioner will provide more detail on the process to be used in this proceeding to be considered by the Commission in a decision in time for the 2014 compliance year.

After such a decision, the next step would be the implementation details of incorporating flexible capacity in the RA program. This could include vetting a clear methodology on how flexibility needs would be calculated annually; which generation would be considered flexible under the adopted definitions; how flexibility would be accounted for; how costs would be allocated for flexible resources; and how all of this would affect procurement and contracting. Parties could examine how these requirements would affect market prices for flexible and inflexible capacity. We agree with Shell's comment that parties should address the current and future need for these flexible procurement obligations, the specific resource characteristics that are sought, the classification of generation facilities in each resource category, and implementation details for the adopted approach.

As we are not adopting either the Energy Division new MCC buckets proposal or the ISO's flexible capacity proposal at this time, we look to the Energy Division's back-up proposal to update MCC buckets and implement a new demand response MCC bucket at this time. This proposal is non-controversial, and responsive to previous Commission decisions. We will adopt the Energy Division proposal to update the percentages used for the MCC buckets to reflect more current load shapes, and to add a bucket specifically for Demand Response resources. Energy Division shall implement this via the RA template.

3.2.3. Coincident Adjustment Factor

The coincident adjustment factor is a number calculated by comparison of total aggregate LSE peak load forecasts and the coincident ISO peak load, in order to make each LSE's peak load forecast reflective of the LSE's contribution to load at the time of ISO's peak load. This factor is used in determining RA obligations by adjusting individual LSE peak forecasts for the fact that each LSE may or may not peak at the time of the ISO's coincident peak.

D.05-10-042 adopted the current coincident adjustment methodology, which uses an average coincident adjustment factor to take advantage of the pooling effect; that is, using an average factor partially balances out the fact that LSEs serve diverse customer classes. This methodology uses historical coincident factors and the same coincident adjustment factor for all LSEs. The Commission adopted this method because "averaging is more stable and easier to calculate, monitor, and apply."[3] LSEs have both coincident demand (the level

[3] D.05-10-042 at 38.

of an LSE's demand at the time of system peak demand) and non-coincident load (the peak level of demand for the customers of that LSE, which may not occur at the time of system peak demand). Per D.05-10-042, each LSE's non-coincidental monthly demand is reduced by a factor that reflects the average load diversity in the ISO's control area in that month.[4] This adjusted demand level is the basis for each LSE's RA obligations.

Historically, all customers were required to take all power from the monopoly IOUs. In the 1990s, customers were allowed to take power from other electric service providers (ESPs), a service known as Direct Access. Direct Access was suspended in the early 2000s, due to adverse market conditions. However, existing Direct Access customers were "grandfathered" into their then-current contracts with ESPs. Direct Access reopened in 2010 under defined circumstances[5] for commercial and industrial customers, who again were allowed to begin migrating from their current ESP to another ESP.

In R.09-10-032, AReM proposed changing the coincident adjustment factor. Instead of using a system average approach as adopted in D.05-10-042, AReM proposed using an approach that is more specific to classes or types of LSEs. Specifically, AReM proposes developing three or more LSE load profiles categories:

1. LSEs serving all customers;
2. LSEs serving commercial and industrial customers only; and

---

4 *Id*.

5 *See* D.10-03-022, implementing Senate Bill 695 (Stats. 2009, ch. 377).

3. LSEs serving only residential and small commercial customers.

Each LSE would be assigned to the load profile category that most closely reflects their particular profile of customers. Based on the load profile categories the California Energy Commission (CEC) would establish three average coincident adjustment factors and apply the adjustment factor to the LSEs associated with each category.

AReM argued that since ESPs serve mainly commercial and industrial customers, the current system average approach competitively disadvantages the ESPs, compared to other LSEs, and shifts costs to Direct Access customers. This is because IOUs have an obligation to serve all customers, while ESPs do not. Thus, according to AReM, using the averaging approach allocates more RA costs to some ESPs and fewer costs to IOUs than if RA costs were allocated based on which customers are actually served by that entity.

Additionally, AReM contended that the re-opening of Direct Access adds to the problem because "since the market re-opening, ESPs have added commercial and industrial load, thereby increasing the 'peakiness' of [IOU] loads that have lost commercial and industrial customers. However because each LSE's RA requirement is calculated using the single, system average coincident adjustment factor, the additional 'peakiness' present in other LSE's load profiles, since market re-opening, is not appropriately reflected in their RA capacity obligations."

In D.11-06-022 at 17, we stated:

> We are committed to greater cost transparency and cost allocation based on cost causation for the RA program. All customer classes should be aware of the costs unique to the "peakiness" of that particular customer class, and all LSEs should face costs consistent with cost causation. An average

> coincidence factor across all customer classes hides certain cost differences among classes and LSEs. In essence, this method serves as a cross subsidy from industrial and commercial customers to residential customers.
>
> Nevertheless, we will not adopt AReM's proposal at this time. We agree that there is significant technical analysis which remains to be produced before this proposal can be implemented. We request Energy Division and CEC staff to work to refine this concept over the course of the next year and provide a recommendation to the Commission in next year's RA proceeding for further consideration and possible implementation in 2013.

AReM states that it has now developed a modified proposal in consultation with the CEC, as discussed in workshops in last year's RA proceeding and in the January 26, 2012 workshop in this proceeding. AReM's proposal (as refined by the CEC) includes two main components: 1) A calculation to determine the applicable coincidence adjustment factor to apply for the annual RA obligations; and 2) a calculation to determine the applicable coincidence adjustment factor to apply for the monthly RA obligations, as follows:

> <u>Annual RA Requirements</u> – The CEC would calculate a LSE-specific coincidence adjustment factor using LSE hourly loads as described in the CEC's January 26th workshop presentation.
>
> <u>Monthly RA Requirements</u> – The CEC would calculate an ESP composite coincidence factor, which would be applied to each ESP's migrating load for the month; migrating load for community choice aggregators would be treated separately.

DRA generally supports the principle whereby all LSEs should face costs consistent with cost causation. However, DRA believes that additional determinations and analysis of the appropriate customer categories of coincident adjustment factor are required before implementation, and therefore opposes making changes at this time. PG&E recommends the Commission not adopt the AReM proposal at this time. PG&E suggests the Commission may want to consider changing the allocation of load diversity after incorporating flexible capacity requirements. SCE agree with PG&E.

Discussion

D.05-12-042 adopted the average coincidence factor adjustment in 2005 partially due to administrative simplicity and overall fairness. Since 2005, conditions have changed. The argument for simplicity is no longer valid. The CEC currently does not use an average coincidence factor in developing forecasts in its Integrated Energy Policy Report process, but instead applies a coincidence factor to each type of load class based on analysis and determinations supporting greater accuracy. The CEC uses a different coincidence factor to determine LSE specific loads. Harmonizing the two coincidence factors would promote greater simplicity, as well as improve cost allocation related to cost causation. Coincidence factors for bundled customers served by IOUs and ESPs are estimated separately, taking into account the customer mix of ESPs versus IOUs, and the restriction on residential load migration.[6]

The average coincident factor method is also inconsistent with methods used to develop a bundled customer forecast in support of the Commission's long-term procurement process. In both RA and long-term procurement proceedings, the Commission has determined that the adopted CEC forecast is to serve as the reference case. The CEC also provides LSE-specific coincidence

---

[6] *See* http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF at 51.

adjustments to each California LSE which is outside of the Commission's jurisdiction for LSEs' use in ISO RA compliance filings. Adopting an LSE-specific methodology for RA would harmonize the long-term procurement process and RA procurement process, as well as improve cost allocation related to cost causation.

As we stated last year in D.11-06-022 at 16-17:

> While changes to the coincident adjustment factor would not directly change the overall distribution of customers among all LSEs, it would change the allocation of costs among LSEs. It is possible that more accurate reflection of cost drivers for different LSEs would increase the incentive for some customers to migrate from IOUs to ESPs, as ESPs' costs decrease and IOUs' costs increase. However, there is no data showing this would be a significant factor. Further, current Direct Access rules provide very limited ability currently for customers to move between IOUs and ESPs. Therefore, any changes in cost allocation resulting from changes to the coincident adjustment factor would appear to be minimal.

We now have more information about how AReM's proposal would work, and specific implementation data from the CEC to make it work. We will adopt the coincident adjustment factor methodology for Annual RA and Monthly RA proposed by AReM with CEC input, as specified in the Ordering Paragraph. After considerable discussion among parties in the RA workshops this year and last and in subsequent filings, there is sufficient record to adopt this proposal. The concerns of DRA, SCE and PG&E are non-specific; any implementation issues can be addressed in future RA proceedings if necessary.

4. Rounding Convention

The current rounding convention for local RA obligations provides that RA obligations are met by rounding to the closest megawatt. This convention was adopted in D.06-06-064 and expanded to system RA obligations in

D.07-06-029. The current rounding convention can lead to small discrepancies between the Energy Division's review of whether obligations have been met, and the ISO's allocation of local RA obligations to LSEs. These small discrepancies can at times cause the ISO to find an LSE as non-compliant while the Energy Division does not.

At the January 27, 2012 workshop, Energy Division proposed rounding to the 0.5 megawatt level instead of the 1.0 megawatt level, which should reduce (though not entirely eliminate) discrepancies. The ISO proposed that the rounding convention should be modified to be consistent with the ISO's 0.1 megawatt rounding requirements. In the transcript for the workshop, Energy Division staff summarized the discussion of what rounding convention should be used for counting RA resources: "(the k)ey questions that came up during the discussion focused on whether the preference was to round two decimal places versus rounding clear up to one megawatt…and (it is) important to keep (in mind)...that some LSEs had trouble purchasing at lower than one megawatt quantity."[7]

In comments, SCE agrees with the ISO that consistency in the rounding conventions across both organizations is preferable, and notes that accuracy favors a more granular approach. If that is too difficult, SCE advocates a 0.1 megawatt rounding approach. DRA proposes that the RA program should utilize megawatt figures for rounding consistent with the ISO for its jurisdictional LSEs, with an exemption allowed for very small LSEs.

---

[7] Reporter Transcripts 28.

We will adopt a new convention of rounding to 0.1 megawatts. This approach is much closer to the ISO's convention, will lead to a minimum of discrepancies between Energy Division and ISO reviews, and will not require different Commission standards for different LSEs.

5. Dynamically Scheduled Resources

Currently, the ISO allows certain dynamically scheduled resources and pseudo tie resources to participate in ISO energy markets. The purpose of these scheduling arrangements is to give the ISO flexibility to operate these resources more efficiently in the ISO's markets and to dispatch them as needed. Currently the methodology used to calculate the qualifying capacity of these resources is vague and needs specificity. At the January 27, 2012 workshop, Energy Division proposed that, for purposes of qualifying capacity calculations used in the RA program, dynamically scheduled resources and pseudo tie resources should be treated as if they were internal ISO resources. These specific types of resources would receive qualifying capacity values based on the methodology used for similar internal ISO resources (pertaining to technology and resources dispatchability). Energy Division noted that to enact this proposal it would be critical that the Commission receives settlement data for these resources comparable to the settlement data received for internal ISO resources.

No party opposes the Energy Division proposal, and we will adopt it.

6. CAC Petition for Modification

On June 21, 2011, CAC filed a Petition for Modification of D.10-06-036, the Commission's Order adopting local procurement obligations for 2011 and further refining the RA program. The Petition contends that D.10-06-036 inadvertently causes load-serving entities to use ratepayer funds to procure redundant and unneeded RA capacity. It further contends that a faulty definition of "system peak demand" results in an undervaluation of the RA capacity from combined heat and power facilities, which, in turn, causes this unnecessary and expensive procurement burden for ratepayers.

The Petition seeks a modification to the system peak demand definition to exclude weekends and holidays from the hours used to calculate the qualifying capacity of combined heat and power resources. CAC claims this revision will strike a better balance between reliability and cost, more closely aligning D.10-06-036, with the principles of the RA program, and maintain consistency between the definition of "system peak demand" in the qualifying capacity counting methodology and the definition of peak hours used in federal and state settings, including a settlement among combined heat and power generators and LSEs recently approved in D.10-12-035.

In a Ruling issued on September 7, 2011, this issue was deferred to this proceeding for consideration and further study. At the January 27, 2012 workshop, Energy Division proposed not to make the changes advocated by CAC in their Petition. Energy Division believes the proposal is administratively burdensome and there is no significant benefit to the RA program in modifying the system peak demand resources. As CAC notes in its comments, the ISO stated at the workshop that system peak can occur during a weekend as well as on weekdays (although CAC claims this is a remote possibility).

No party other than CAC commented on the Energy Division proposal. We do not believe that CAC's Petition would improve the RA program, while it would add administrative complexity. We will not make the changes recommended by CAC, and we therefore deny the Petition for Modification.

7. Demand Response Counting Issues

Load Impacts for Dynamic Rate Programs

In D.11-06-022, Ordering Paragraph 14, the Commission allowed PG&E to receive load impacts averaged over the hours of 2 p.m. to 6 p.m. for their dynamic rates DR programs, instead of the standard 1 p.m. to 6 p.m. interval over which load impacts are averaged for other DR programs. PG&E was ordered to "propose changes to the current large commercial and industrial and agricultural customers PDP [Peak Day Pricing] operational period of 2 p.m. to 6 p.m. to 1 p.m. to 6 p.m. in its 2012 Rate Design Window (RDW) application." PG&E has proposed the change to the operational hours in compliance with the requirement for its Peak Day Pricing in its RDW application,[8] which is pending Commission's approval.

PG&E is concerned that the Commission may not issue a decision in time for PG&E to implement the new operation hours prior to the 2013 RA Year Ahead compliance filing. PG&E requests that for purposes of the load impacts from this program, the impacts would be averaged over the 2 p.m. to 6 p.m. time interval as was done for this program in the 2012 RA compliance year in the event PG&E does not receive Commission authorization to shift the dynamic rate operating hours in time for implementation in 2013. If the shift is authorized in time to allow for implementation for 2013, load impacts would be computed over the 1 p.m. to 6 p.m. time interval consistent with other DR programs.

---

8 *See* A.12-02-020.

We will adopt this continued treatment for PG&E's dynamic rate programs in general and Peak Day Pricing in particular, to account for timing of other Commission actions.

Local Dispatchability for Certain DR programs

In D.11-10-003, the Commission ruled that DR resources, not including dynamic pricing programs, must be capable of being dispatched by Local Capacity Area (LCA) by 2013 in order to receive local resource adequacy credit. That decision ruled that utilities may request an exemption to the 2013 requirement for specific demand response programs if: 1) the Commission proceedings addressing demand response program designs and funding issues have not concluded with sufficient time to modify the program in question prior to the 2013 RA compliance year; or 2) the Commission has found in a demand response proceeding that a particular demand response program should not be modified to comply with the rule for various reasons, e.g., cost-effectiveness or implementation-related issues.[9]

PG&E requests an exemption to the Local Dispatchability Requirement for its Aggregator Managed Program (AMP), Capacity Bidding Program (CBP), and Demand Bidding Program (DBP) for the 2013 RA compliance year. PG&E reasons that the Commission did not issue D.12-04-045 approving PG&E's 2012-2014 demand response program budgets until April 19, 2012, four months after the initial schedule. In addition, the Commission's approval of the programs subject to the exemption is conditional subject to the Advice Letter requirements between 60 to 90 days after the decision. The Commission's final

[9] D.11-10-003 at 8.

approval of these programs will not allow sufficient time for PG&E to implement the necessary changes to enable the local dispatchability function prior to the RA Year-Ahead compliance filing date (in October 2012).

We grant PG&E's request because it meets the criteria outlined in our 2012 RA decision, D.11-10-003. The Decision ruled that utilities may request an exemption to the 2013 RA local dispatchability requirement if the Commission proceedings addressing demand response program designs and funding issues were not concluded with sufficient time to modify the program in question prior to the 2013 compliance year.[10] However, we emphasize the importance of the local dispatchability requirement and require PG&E to implement the changes by May 1, 2013.

8. Comments on Proposed Decision

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

9. Assignment of Proceeding

Mark J. Ferron is the assigned Commissioner and David M. Gamson is the assigned ALJ in this proceeding.

Findings of Fact

1. The assumptions, processes, and criteria used for the 2013 Local Capacity Requirements study were discussed and recommended in an ISO stakeholder

---

[10] D.11-10-003 at 8.

meeting, and they generally mirror those used in the 2007 through 2012 Local Capacity Requirements studies.

2. In previous RA decisions, the Commission delegated ministerial aspects of program administration to the Energy Division.

3. There is a need for refinements to the RA program to further define elements of flexibility with regard to multi-year contracts for local capacity requirements.

4. Proposals by Energy Division and the ISO to address flexible capacity, while helpful, require further consideration and detail before adoption.

5. D.05-10-042 adopted the current coincident adjustment methodology, which uses an average coincident adjustment factor to take advantage of the pooling effect.

6. An average coincidence factor across all customer classes hides certain cost differences among classes and LSEs.

7. An LSE-specific coincidence adjustment factor for hourly RA and an ESP composite coincidence factor for monthly RA more accurately allocates RA costs.

8. The Energy Division uses a rounding convention of 1 MW for RA compliance purposes, while the ISO uses a rounding convention of .01 megawatt for RA purposes.

9. The difference between the Energy Division and the ISO in RA rounding conventions can lead to small discrepancies, with sometimes leads to an LSE being deemed out of compliance by the ISO but not the Energy Division.

10. Small LSEs can have difficulty complying with an RA rounding convention which is too restrictive.

11. Currently, the ISO allows certain dynamically scheduled resources and pseudo tie resources to participate in ISO energy markets in order to give the ISO

flexibility to operate these resources more efficiently in the ISO's markets and to dispatch them as needed. The methodology used to calculate the qualifying capacity of these resources is vague and needs specificity.

12. The June 21, 2011 CAC Petition seeks a modification to the system peak demand definition to exclude weekends and holidays from the hours used to calculate the qualifying capacity of combined heat and power resources. This proposal is administratively burdensome and there is no significant benefit to the RA program in modifying the system peak demand resources.

13. In response to D.11-06-022, PG&E has proposed to change to the operational hours for its dynamic rates DR programs in compliance with the requirement for its Peak Day Pricing in its RDW application, which is pending Commission's approval.

14. D.11-10-003 allowed utilities to request an exemption to the 2013 requirement for specific demand response programs to be dispatchable by Local Capacity Area by 2013 in order to receive local resource adequacy credit under specified conditions.

15. The Commission did not issue D.12-04-045 approving PG&E's 2012-2014 demand response program budgets until April 19, 2012, subject to Advice Letter requirements between 60 to 90 days after the decision.

Conclusions of Law

1. The ISO's 2013 Local Capacity Technical Analysis Final Report and Study Results, dated April 30, 2012, should be approved as the basis for establishing local procurement obligations for 2013 applicable to Commission-jurisdictional Load Serving Entities.

2. Because the current local RA program establishes procurement obligations for the following year, Load Serving Entities should only be responsible for procurement in a local area to the level of resources that exist in the area.

3. Energy Division should implement the local RA program for 2013 in accordance with the adopted policies in this and previous decisions.

4. Increased transparency and accurate cost information are Commission objectives in the resource adequacy program.

5. It is necessary to further consider issues related to flexible capacity in another portion of this proceeding.

6. It is reasonable to adopt a coincidence adjustment factor which includes an LSE-specific coincidence adjustment factor for hourly RA and an ESP composite coincidence factor for monthly RA.

7. Rounding to 0.1 megawatts for Commission RA purposes is reasonable because this convention is much closer to the ISO's convention, will lead to a minimum of discrepancies between Energy Division and ISO reviews, and will not require different Commission standards for different LSEs.

8. It is reasonable to adopt the Energy Division proposal that, for purposes of qualifying capacity calculations used in the RA program, dynamically scheduled resources and pseudo tie resources should be treated as if they were internal ISO resources.

9. Load impacts related to PG&E's dynamic rate programs should be averaged over the interval of 2 p.m. to 6 p.m. for purposes of 2013 RA compliance as an exemption to RA rules, because PG&E's proposed changes to the operational hours for its dynamic rates DR program in its Rate Design Window application will not be approved in time for the next RA compliance filing.

10. PG&E's AMP, DBP, and CBP programs should count for RA in 2013 compliance year even though they are not yet locally dispatchable, as the timing of D.12-04-045 meets one of the requirements in D.11-10-003 for an exception from that decision's local dispatchability requirement for certain DR programs.

11. It is not reasonable to grant the June 21, 2011 Cogeneration Association of California Petition for Modification of D.10-06-036.

O R D E R

IT IS ORDERED that:

1. The California Independent System Operator's 2013 Local Capacity Technical Analysis Final Report and Study Results, dated April 30, 2012, is adopted as the basis for establishing local procurement obligations for 2013 applicable to Commission-jurisdictional load-serving entities as defined by Public Utilities Code Section 380.

2. The "Option 2/Category C" Local Capacity Requirements set forth in the California Independent System Operator's 2013 Local Capacity Technical Analysis Final Report and Study Results, dated April 30, 2012, are adopted as the basis for establishing local resource adequacy procurement obligations for load-serving entities subject to this Commission's resource adequacy program requirements. The Local Capacity Requirements for 2013 are as follows:

	2013 Local Capacity Requirements Needs		
Local Area Name	**Existing Capacity Needed**	**Deficiency**	**Total (Megawatts)**
Humboldt	190	22	**212**
North Coast / North Bay	629	0	**629**
Sierra	1712	218	**1930**
Stockton	413	154	**567**
Greater Bay	4502	0	**4502**
Greater Fresno	1786	8	**1786**
Kern	483	42	**525**
Los Angeles Basin	10295	0	**10295**
Big Creek/ Ventura	2241	0	**2241**
San Diego	2938	144	**3082**
Total	**25189**	**580**	**25769**

3. The local resource adequacy program and associated requirements adopted in Decision 06-06-064 for compliance year 2007, and continued in effect by Decision 07-06-029, Decision 08-06-031, Decision 09-06-028, Decision 10-06-036 and Decision 11-06-022 for compliance years 2008, 2009, 2010, 2011 and 2012, respectively, are continued in effect for compliance year 2013, subject to the modifications, refinements, and local capacity requirements adopted in the ordering paragraphs in this decision.

4. The resource adequacy program shall be modified so that the coincidence adjustment factor uses a load service entity-specific coincidence adjustment factor for annual resource adequacy requirements, and an energy service provider-composite coincidence factor for monthly resource adequacy requirements, as follows:

> Annual Resource Adequacy Requirements – The California Energy Commission will calculate a Load Serving

Entity-specific coincidence adjustment factor using Load Serving Entity hourly loads; and

<u>Monthly Resource Adequacy Requirements</u> – The California Energy Commission will calculate an Electric Service Provider-composite coincidence factor, which would be applied to each Electric Service Provider's migrating load for the month; migrating load for community choice aggregators would be treated separately.

5. The resource adequacy program is modified so that load serving entities shall round to 0.1 megawatts for resource adequacy compliance.

6. The resource adequacy program should be modified so that, for purposes of qualifying capacity calculations used in the resource adequacy program, dynamically scheduled resources and pseudo tie resources should be treated as if they were internal California Independent System Operator resources.

7. Energy Division shall update the percentages used for the Maximum Cumulative Capacity Buckets to reflect more current load shapes, and to add a bucket specifically for Demand Response resources, and to implement this via the Energy Division's Resource Adequacy template.

8. The June 21, 2011 Cogeneration Association of California Petition for Modification of Decision 10-06-036 is denied.

9. Load impacts related to Pacific Gas and Electric Company's dynamic rate programs shall be averaged over the interval of 2 p.m. to 6 p.m. for purposes of 2013 Resource Adequacy compliance.

10. Pacific Gas and Electric Company's Aggregator Managed Program, Capacity Bidding Program and Demand Bidding Program shall be counted for Resource Adequacy in the 2013 Resource Adequacy compliance year. These programs must be locally dispatchable by May 1, 2013.

11. Rulemaking 11-10-023 shall remain open.

This order is effective today.

Dated ____________________________, at San Francisco, California.