STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

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TO ALL PARTIES IN RULEMAKING 05-12-013

The revised proposed decision of ALJ Wetzell is enclosed. The revisions address comments filed and served on December 2, 2009, and reply comments filed and served on December 11, 2009, to the initial proposed decision dated November 3, 2009. The revised proposed decision is on the Commission's April 8, 2010 meeting agenda. The ALJ Division will request the Commission to hold the item to consider the additional comments provided for by separate ruling.

When the Commission acts on the revised 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 the *Administrative Law Judge's Ruling Providing for Comments and Replies Regarding the Revised Proposed Decision* issued on March 30, 2010. As set forth in the ruling, comments are due April 16, 2010 and replies to comments are due April 23, 2010. Comments should be filed in conformance with Rule 14.3(b)(c), and (d) of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at http://www.cpuc.ca.gov. Opening comments shall not exceed 25 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 Wetzell at msw@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:tcg

Attachment

Decision **REVISED PROPOSED DECISION OF ALJ WETZELL** (Mailed 3/30/2010)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program.	Rulemaking 05-12-013 (Filed December 15, 2005)

DECISION ON PHASE 2 – TRACK 2 ISSUES: ADOPTION OF A PREFERRED POLICY FOR RESOURCE ADEQUACY

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Appendix A Public Utilities Code Section 380

Appendix B Resource Adequacy Decisions, 2004-2009

DECISION ON PHASE 2 – TRACK 2 ISSUES: ADOPTION OF A PREFERRED POLICY FOR RESOURCE ADEQUACY

1. Summary of Decision

Public Utilities Code Section 380 directs us to establish resource adequacy requirements applicable to investor-owned utilities and other load-serving entities in order to facilitate development of new generating capacity and retention of existing generating capacity that is economic and needed for reliability. In this decision we evaluate how well the resource adequacy program is achieving these and other objectives that include reliability at least cost, equitable allocation of the costs of reliability, and alignment of the resource adequacy program with California's goals for the environment and for competitive markets. We then evaluate options for modifying the program and determine whether any of them would more effectively meet the program objectives.

The resource adequacy program relies upon the imposition of short-term (year-ahead) procurement obligations on load-serving entities. This approach has worked well to assure the availability of existing resources to the California Independent System Operator Corporation for reliable grid operations. However, many parties are concerned that it does not adequately foster investment in new generation, and believe that it is necessary to modify the program by providing for a multi-year forward commitment of capacity resources. We evaluate these concerns and conclude that the disadvantages of a multi-year procurement mandate outweigh its positive aspects.

We also consider whether to adopt a policy for a centralized capacity auction mechanism administered by the California Independent System

Operator Corporation, or to continue the resource adequacy program's reliance on bilateral contracting for capacity. While each approach has its particular advantages, we find, on balance, that maintaining the current bilateral contracting approach best meets the program objectives. Of particular significance is the fact that under the bilateral approach, the Commission would retain its broad scope of authority over the resource adequacy program. In contrast, a decision to endorse a centralized capacity auction mechanism would be a decision to hand substantial components of resource adequacy over to the Federal Energy Regulatory Commission. Such a move is at best premature. We therefore decide to continue the bilateral contracting approach.

We find that the bilateral approach recommended by the Bilateral Trading Group is the option that best comports with our threshold policy determinations for resource adequacy, and we provide guidance for further proceedings to refine and implement the proposal. Finally, we review proposals for allowing load-serving entities to opt out of the Cost Allocation Mechanism adopted in Decision 07-06-029, and determine that none of them is ready for adoption.

With this decision we complete the second track of Phase 2 of this proceeding. Track 3 of Phase 2 was established to address resource adequacy obligations for small and multi-jurisdictional load-serving entities that are not currently subject to the resource adequacy program. We find that it is appropriate to close this proceeding and resolve the Track 3 issues in a more appropriate proceeding.

2. Procedural Background

This decision completes the second of three procedural tracks that were established for Phase 2 of this resource adequacy (RA) proceeding.[1] The Phase 2 Scoping Memo identified eight topics for consideration in Track 2, summarizing them as follows:

a. Centralized capacity market, bilateral trading, and alternative market design

b. Registration/tagging for RA capacity

c. Multi-year forward commitment time horizons

d. [Load-serving entity (LSE)] opt-out from cost allocation mechanism (D.06-07-029)

e. Coordination of RA program with [the California Independent System Operator Corporation's (CAISO's) Market Redesign and Technology Update (MRTU)] as necessary

f. Procurement obligations for resource mix and ancillary services

g. Market power mitigation

h. Planning Reserve Margin (Phase 2 Scoping Memo at 17.)

In this decision we examine proposals that focus on topics a, c, and d. Market power mitigation is considered in the context of our evaluation of the other topics, not as a stand-alone issue. We are considering the planning reserve margin (PRM) in a separate proceeding (Rulemaking (R.) 08-04-012). Other topics were, or will be, addressed elsewhere.

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[1] See *Assigned Commissioner's Ruling and Scoping Memo for Phase 2* (Phase 2 Scoping Memo), issued December 22, 2006. Track 1 addressed RA program implementation for the 2008 compliance year and was concluded by Decision (D.) 07-06-029. Track 3 addresses how the RA program will be extended to small and multi-jurisdictional LSEs. On June 17, 2008 the Assigned Commissioner issued an amended scoping memo for Phase 2 (Amended Phase 2 Scoping Memo). The statutory deadline for resolving the proceeding was extended by the Commission in several decisions.

Pursuant to the schedule and procedure established by the Phase 2 Scoping Memo and subsequent rulings by the assigned Commissioner and Administrative Law Judge (ALJ), the record for Track 2 was developed through filed proposals, stakeholder meetings and workshops facilitated by the Commission's Energy Division, an Energy Division report on Track 2 issues (Staff Report) prepared in collaboration with the CAISO,[2] a supplemental staff report, motions to supplement the record, and pre- and post-workshop comments. The following table summarizes this process:

Development of the Track 2 Record

Initial proposals filed	March 30, 2007
Energy Division-facilitated stakeholder meeting	April 25, 2007
Pre-workshop comments filed	May 18, 2007
Pre-workshop reply comments filed	July 13, 2007
New/updated proposals filed	August 3, 2007
Energy Division-facilitated workshops	August 15, 20-22, and 27-28, 2007
Energy Division Staff Report on Track 2 Issues released	January 18, 2008
Post-workshop comments filed	February 29, 2008
Post-workshop reply comments filed	March 14, 2008
Motions to supplement the record granted by amended Phase 2 Scoping Memo	June 17, 2008
Energy Division-facilitated workshops	August 22 and 25, 2008
Motion to supplement the record granted by ALJ Ruling	August 6, 2008
Supplemental Staff Report issued	September 17, 2008
Comments on supplemental staff report filed	October 1, 2008
Reply comments on supplemental staff report filed	October 8, 2008

As detailed in the following table, which lists the parties and indicates the acronyms used in this decision to identify parties, 31 parties or party coalitions filed a total of 90 documents containing Track 2 proposals and/or comments.

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[2] Although the CAISO collaborated with our Energy Division staff in the preparation of the Staff Report, the CAISO maintained its party status and did not participate in the Commissions deliberations.

Parties Filing Track 2 Proposals and/or Comments

Filing Party or Parties For party groups, the parties listed below did not, in all cases, participate in each of the filings of the group	**Acronym or Title for Party or Party Group**	**Initial Proposals** **3/30/07**	**Pre-workshop comments** **5/18/07**	**Pre-workshop reply comments** **7/13/07**	**New/ updated proposals** **8/03/07**	**Post-workshop comments** **2/29/08**	**Post-workshop reply comments** **3/14/08**	**Supp. comments** **10/01/08**	**Supp. reply comments** **10/08/08**
Aglet Consumer Alliance	Aglet	X	X	X	X	X	X	X	X
Alliance for Retail Energy Markets	AReM	X	X	X		X	X	X	
Bilateral Trading Group (APS Energy Services, California Electricity Oversight Board, California Large Energy Consumers Association, California Manufacturers & Technology Association, City and County of San Francisco, Shell Energy North America (US), L.P., DRA, Energy Users Forum, J. Aron & Company, TURN, and Direct Energy, LLC.)	BTG	X	X	X		X	X	X	
Cogeneration Association of California	CAC	X							
California Independent System Operator Corporation	CAISO	X				X	X	X	X
Calpine Corporation	Calpine	X				X	X	X	X
California Forward Capacity Market Advocates (FPL Energy, NRG Energy, Reliant Energy, SCE, and SDG&E	CFCMA		X	X	X	X	X	X	X
Capacity Market Advocacy Group (Commerce Energy, Constellation Energy Commodities Group, Inc, Edison Mission Energy, FPL Energy Project Management, Mirant Corporation, Reliant Energy, Inc, SCE, and SDG&E)	CMAG	X							
California Municipal Utilities Association	CMUA					X			
Complete Energy Holdings LLC	Complete Energy					X			X
Constellation Energy Commodities Group, Inc., Constellation NewEnergy, Inc., and Constellation Generation Group, LLC	Constellation	X	X	X	X	X	X	X	
Coalition of California Utility Employees	CUE		X			X		X	
Division of Ratepayer Advocates	DRA	X							

Filing Party or Parties For party groups, the parties listed below did not, in all cases, participate in each of the filings of the group	**Acronym or Title for Party or Party Group**	**Initial Proposals** **3/30/07**	**Pre-workshop comments** **5/18/07**	**Pre-workshop reply comments** **7/13/07**	**New/ updated proposals** **8/03/07**	**Post-workshop comments** **2/29/08**	**Post-workshop reply comments** **3/14/08**	**Supp. comments** **10/01/08**	**Supp. reply comments** **10/08/08**
Dynegy Morro Bay LLC, Dynegy Moss Landing LLC, Dynegy South Bay, LLC, and Dynegy Oakland LLC	Dynegy						X	X	X
Electricity Consumers Resource Council	ELCON	X							
Ice Energy, Inc.	Ice Energy					X			
Independent Energy Producers Association	IEP	X	X			X	X	X	
Constellation; SDG&E; AES Southland, LLC; Calpine; CFCMA; Complete Energy; Dynegy; IEP; Mirant; and Sempra Global	N/A						X		
AReM; AES Southland, LLC; CFCMA; Complete Energy; Constellation; Dynegy; IEP; LS Power Associates, LP; Mirant; and Sempra Global	N/A								X
Kinder Morgan Energy Partners, L.P.	Kinder Morgan					X			
Mirant California LLC, Mirant Delta LLC, and Mirant Potrero LLC	Mirant	X	X			X			X
Morgan Stanley Capital Group, Inc.	Morgan Stanley		X						
NRG Energy, Inc.	NRG	X	X						
Pacific Gas and Electric Company	PG&E	X	X	X	X	X	X	X	X
PPM Energy	PPM Energy	X							
Reliant Energy, Inc.	Reliant	X	X						
Southern California Edison Company	SCE	X	X						
San Diego Gas & Electric Company	SDG&E	X							
Sempra Global	Sempra Global					X			
The Utility Reform Network	TURN						X		
Western Power Trading Forum	WPTF					X			

3. Development of a Preferred Resource Adequacy Policy

3.1. Introduction

California has pursued a hybrid wholesale electric generation market in which the Commission expects the major investor-owned electric utilities (IOUs) (PG&E, SCE, and SDG&E) and independent merchant generation firms to compete in the provision of needed generation services. At the same time, retail electric service can be provided by three types of LSEs in the IOUs' service territories: the IOUs themselves, electric service providers (ESPs), and community choice aggregators (CCAs). Also, wholesale electric energy prices are capped by order of the Federal Energy Regulatory Commission (FERC). It is against this backdrop that the Commission has established explicit RA policies and regulations through a series of decisions that date back to 2004.[3] It has done so to:

- Ensure that there is adequate, cost-effective investment in electric generation capacity for Californians served by the three major IOUs and the other jurisdictional LSEs that operate in those IOUs' service territories,
- Ensure that installed generation capacity is made available to the CAISO when and where it is needed for reliable transmission grid operations, and
- Ensure that the costs of providing such capacity are equitably apportioned to those who benefit from the provision of capacity and cause the costs to be incurred.[4]

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[3] See Appendix B to this decision.

[4] See, for example, the first RA implementation decision: "The Commission takes this action to promote investment in the resources needed to reliably serve California's growing demand for electricity and ensure that those resources are available to the [CAISO], all while effectively and fairly allocating procurement and reliability responsibilities among market participants and oversight agencies." (D.05-10-042 at 2.)

Taken together, the policies and implementing regulations that have been adopted since 2004 constitute this Commission's RA program. Prior to the advent of this regulatory approach to ensuring generation reliability, assurance of sufficient and cost-effective investment in generation capacity was left to market forces under an industry restructuring scheme that was implemented in 1998. Prior to that, assurance of investment in generation was the domain of the IOUs acting under the oversight of this Commission and the California Energy Commission (CEC).

In this decision, we take a pause from our ongoing implementation and refinement of the RA program to assess whether the current program structure or an alternative approach best meets the overall program objectives. As explained in the order instituting this rulemaking,[5] a review of "second generation" RA topics including a multi-year forward commitment and a review of capacity markets was contemplated by the Commission in D.04-10-035.

Consideration of the options before us in Track 2 requires that we evaluate whether and how to modify the RA program in order to more effectively achieve the program's objectives. We begin the evaluation by reviewing and restating our objectives for the RA program.

3.2. Program Objectives

The Commission's earliest actions to establish the RA program predated the enactment of Section 380,[6] but that statute is closely aligned with the Commission's previously stated RA objectives and is the foundation for the

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[5] Order Instituting Rulemaking at 7.

[6] Section references herein are to the Public Utilities Code unless otherwise noted. Section 380 is reproduced in Appendix A.

program going forward.[7] Section 380(b) directs the Commission to achieve all of the following objectives through RA requirements:

> (1) Facilitate development of new generating capacity and retention of existing generating capacity that is economic and needed.
>
> (2) Equitably allocate the cost of generating capacity and prevent shifting of costs between customer classes.
>
> (3) Minimize enforcement requirements and costs.

Section 380(h) reiterates and expands upon these objectives, directing the Commission to determine and authorize the most efficient and equitable means for achieving all of the following:

> (1) Meeting the objectives of [Section 380].
>
> (2) Ensuring that investment is made in new generating capacity.
>
> (3) Ensuring that existing generating capacity that is economic is retained.
>
> (4) Ensuring that the cost of generating capacity is allocated equitably.

Taking into account the statutory objectives and the other requirements of Section 380, as well as the Commission's prior policy determinations, the RA program's main objectives can be restated as follows:[8]

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[7] Section 380, added to the Public Utilities Code by Assembly Bill (AB) 380 (Stats. 2005, Ch. 367, Sec. 1), became effective January 1, 2006. AB 3048 made technical amendments to Section 380 effective January 1, 2009. (Stats. 2008, Ch. 558, Sec. 13.)

[8] The objectives discussed here are, in part, specific to the three largest IOUs and the other LSEs that operate in their service areas. As noted earlier, Track 3 is our forum to consider expansion of the RA program to include all jurisdictional LSEs. Pending resolution of Track 3 issues, we do not necessarily intend that the objectives presented here will apply in full to all LSEs.

I. Reliability - The Commission seeks to ensure the continued availability of generation capacity needed to reliably serve load in the IOUs' service territories.

The Commission determines an appropriate level of generation reliability in establishing the PRM. It then seeks to facilitate investment to develop new and retain existing generating capacity that is needed to meet forecasted peak demand plus the PRM. Additionally, the Commission seeks to ensure that installed capacity is made available to the CAISO when and where it is needed for reliable transmission grid operations.

II. Least Cost Principle - The Commission seeks to minimize RA procurement and compliance costs faced by LSEs and their customers, program administrative costs, and the costs of programs that are impacted by the RA program.

Minimizing ratepayer costs to the extent consistent with the provision of adequate utility service is a bedrock mission of Commission regulation. As the Commission stated in 2004 regarding the development of RA policy for reliability:

> [W]e cannot neglect our other primary public duty: protection of ratepayers from excessive charges. Increasing supply will cost money, and ensuring reliability does not come cheap. We understand the need to provide mechanisms to pay competitive market costs to new and continuing suppliers. However, we will not 'pay any price' or require utilities to sign contracts that meet these requirements at any cost. (D.04-10-035 at 15.)

The following year, the Commission reiterated the importance of balancing cost and reliability when it stated that "'reliability at any cost' is not a policy option." (D.05-10-042 at 8.)

In designing RA requirements to achieve the reliability objective, the Commission seeks to minimize both procurement costs and program administration costs incurred by the regulatory agencies as well as regulated entities. In addition, the Commission seeks opportunities to incorporate program elements that might reduce costs that are external to the RA program. For example, other things being equal, the Commission would prefer an alternative that facilitates the ability to make cost-effective tradeoffs between investments in transmission upgrades and resource additions.

> ***III. Equitable cost allocation - The Commission seeks to ensure that the costs of providing the capacity needed for peak demand and the PRM are equitably allocated to, and paid for by, those who benefit from and cause the costs to be incurred.***

Section 380(e) requires that we implement and enforce RA requirements in a nondiscriminatory manner among LSEs. By successfully implementing this requirement, we will promote equitable cost allocation and prevent cost shifting.

Some parties have expressed concern that if the RA program does not impose sufficiently robust procurement obligations on all LSEs and ensure that those obligations are fulfilled, an individual LSE might be able to shift procurement responsibility to the CAISO or to IOUs, and thereby shift costs to other LSEs and their customers.

IV. Coordination with related programs and policies - The Commission seeks to structure the RA program in coordination with policies embodied in California's Energy Action Plan[9] and other Commission and State initiatives that could be impacted by the RA program.

The RA program is not being developed and implemented in isolation from the State's other policies for the electric power sector. To the extent possible, and consistent with the objectives of reliability, least cost, and equitable cost allocation, the RA program should support, and should not thwart, the objectives of increased reliance on renewable energy resources and demand response (DR) capabilities, reduced greenhouse gas (GHG) emissions, and competitive wholesale and retail electric markets.[10]

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[9] In 2003, the Commission, the CEC, and the California Power Authority adopted an Energy Action Plan (EAP), articulating a single, unified approach to meeting California's electricity and natural gas needs. A key element was the "loading order" which specified California's policy to invest first in energy efficiency and demand response, followed by renewable resources, and only then in clean conventional electricity supply. In 2005, the Commission and the CEC adopted a second plan, EAP II, to reflect policy changes and actions. Since then, the Commission and the CEC have updated the EAP. The 2008 EAP update is available at the Commission's website using the following link:

> http://www.cpuc.ca.gov/NR/rdonlyres/58ADCD6A-7FE6-4B32-8C70-7C85CB31EBE7/0/2008_EAP_UPDATE.PDF

[10] As the ALJ provided in a ruling regarding the submission of Track 2 proposals:

> To the extent possible, the Commission should be in a position to adopt policies for the RA program that are neutral with respect to other broad policy initiatives that may be underway or contemplated for the California electricity market. For example, the Commission's decision in this proceeding on whether to proceed with a centralized capacity market or a bilateral trading approach should not be designed primarily to promote movement towards the full reopening of the retail market nor would it in any way preclude such movement. (*Administrative Law Judge's Ruling on Track 2 Proposals*, February 28, 2007.)

We note that the CAISO largely shares our program objectives. (Staff Report at 22-23). In particular, the CAISO believes the RA framework must serve the primary goal of providing electric service to CAISO control area consumers at the desired level of service reliability and at stable and reasonable prices. The CAISO also believes that the RA program should induce timely and efficient investment in new supply infrastructure and ensure sufficient and dependable availability of supply capacity on a day-to-day basis to support reliable operation of the transmission system. CFCMA also generally agrees with our objectives:

> The primary goals of an RA mechanism must be to ensure long-run reliability of the California electric grid, at least cost, with equitable responsibility for these costs, and the reasonable opportunity of investors (be they IOUs, other LSEs, or private investors) to recover their investment and earn a fair rate of return. In order for these primary goals to be met, the RA mechanism must facilitate development of new generation and retention of existing generation that is economic and needed. (CFCMA Comments at 12.)

The BTG supports its proposal in this proceeding on the grounds that it is the option most consistent with an eventual transition to an "energy-only" construct for California's electric industry. As envisioned by the BTG, procurement and reliability would center on energy prices, and the concept of a capacity product and capacity payments to generators would be gradually eliminated. Eventually, energy prices alone would provide incentives for forward investment. Regardless of the merits of this vision, we do not find such a regime to be consistent with Section 380(c), which requires that LSEs maintain

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We affirm this neutrality principle as consistent with the objective of program and policy coordination. We note that the qualifying phrase "[t]o the extent possible" means that where RA program objectives conflict with each other, the primary objectives of reliability, least cost, and equitable allocation take precedence over the objective of program and policy coordination.

physical generation capacity adequate to meet load plus planning and operating reserves. Accordingly, we do not see movement to an energy-only regime as an RA program objective.

Mirant takes the position that "no capacity market will be successful as long as utility investment is allowed to continue" and that as soon as the new investment paradigm it recommends is operational, it is "critical for the Commission to take action to end reliance on utility investment in new generation." (Mirant comments at 3.) As we noted at the outset, the RA program was conceived in the context of California's decision to have a hybrid generation market in which IOUs and merchant generation firms compete to provide investment. It is not an objective of the RA program to change that determination. Moreover, a decision to rescind the hybrid market policy is not within the scope of this proceeding.

3.3. Description of the Current Program

The RA program currently applies to California's three large IOUs and the other LSEs under Commission jurisdiction that operate in those IOUs' service territories. The program is implemented through cooperative arrangements with the CEC and the CAISO and the authority of the Commission. It consists of a "system" and a "local" component and can be described as follows:

System RA Component

- Each July, the Commission establishes LSE–specific monthly peak load forecasts for the following year. These official load forecasts are based on information provided by the LSEs and adjustments by CEC staff working with the Commission's staff. To provide for consistency with other planning processes, the adjustments ensure that the sum of individual LSE peak forecasts matches the CEC's adopted demand forecast.

- A PRM factor (currently 15%) is added to each LSE's official load forecast to calculate the LSE's RA procurement obligation for the next year.
- Each LSE makes an annual compliance filing to the Commission demonstrating that it has acquired at least 90% of the capacity needed to fulfill its procurement obligation (peak load forecast plus PRM) for the following "summer" season (May through September). The Commission has historically set an October date for these "year-ahead" compliance filings.
- In addition to the annual procurement obligation described above, LSEs make month-ahead compliance filings to show that they have acquired 100% of the capacity needed to meet their system RA procurement obligation for each month of the year. Adjustments to the LSE's previously established load forecast for the month are required to account for load migration (movement of retail customers from one LSE to another).
- For both the year-ahead and month-ahead compliance filings, the resources nominated by the LSE must meet Net Qualifying Capacity (NQC) counting rules based on the resource type. Pursuant to a "must-offer obligation" (MOO), qualifying resources must be available to the CAISO for its day-ahead market.
- Due to limits on the carrying capacity of Transmission Path 26 between Northern and Southern California, the extent to which LSEs may rely upon resources that use Path 26 to meet their system procurement obligation is limited by the "Path 26 Counting Constraint."
- LSEs are subject to Commission-imposed sanctions for failure to meet their system procurement and compliance filing obligations.

Local RA Component

- Based on a CAISO study of the local capacity requirements (LCRs) in defined, transmission-constrained local areas that uses the CEC's adverse peak demand forecasts, the Commission establishes local procurement obligations to be met by LSEs each year.
- At the same time that LSEs make their annual year-ahead system RA compliance filings, they also make compliance filings showing they have procured 100% of the capacity needed to fulfill their local

procurement obligations. Unlike the System RA obligations, which applies to the following May through September period, the Local RA obligation applies to the following calendar year.

- Rules for counting the NQC of resources nominated to meet the LSE's local procurement obligation are generally similar to the counting rules for the system requirement.
- LSEs are subject to Commission-imposed sanctions for failure to meet their local procurement and compliance filing obligations.

As can be seen, the RA program focuses on capacity procurement obligations and compliance reporting by LSEs. It does not, by explicit rule, require capacity payments to generators. However, capacity payments are an intended element of the program:

> [B]ecause capped energy pricing limits the revenues available for recovery of investment costs, which is particularly problematic for resources that are only needed for a few peak hours, we will look favorably to mechanisms that promote the recovery of investment costs through payments for capacity. (D.05-10-042 at 9.)

Similarly, the current RA program does not prescribe the market structure or mechanisms under which LSEs will acquire capacity. However, it is the Commission's expectation that the procurement obligations will be met by LSEs either through self-supply or through bilateral transactions with suppliers of capacity.

As a complement to this Commission's RA program, the CAISO exercises FERC-approved authority to engage in backstop procurement of resources when it deems such procurement to be necessary. When the RA program commenced, the CAISO maintained the Reliability Capacity Services Tariff (RCST) as a backstop mechanism. The RCST was succeeded by the Transitional Capacity Procurement Mechanism (TCPM), which in turn has been replaced with the CAISO's Interim Capacity Procurement Mechanism (ICPM). The CAISO also identifies generators that must be available for a particular area due to transmission constraints, and enters into "reliability must run" (RMR) contracts with them as it deems necessary. The Commission has stated its policy that the use of RMR contracts should be minimized (D.04-07-028 at 13), and a major function of the Local RA program component is to supplant RMR procurement with LSE-based procurement. More generally, the Commission has noted that "[o]ver-reliance on backstop procurement is fundamentally at odds with the LSE-based procurement objective of the RA program." (D.07-06-029 at 44.)

3.4. Assessment of the Current Program

3.4.1. Overview

As a stand-alone regulatory enterprise, the RA program is relatively new. The system component took effect in June 2006 and the local component took effect in 2007. This provides a short span of operation upon which to base conclusions about how well the program objectives have been met.

Moreover, the program has continually evolved in several important respects and it therefore represents a moving target for evaluation purposes. As emphasized in D.06-04-040, the RA program in place for 2006-2008 was transitional in nature. The system component did not take full effect until the ability of LSEs to count "liquidated damages" (LD) contracts towards their procurement obligations was phased out with the 2009 compliance period.[11] The Path 26 Counting Constraint was first implemented in 2008. Certain NQC

[11] D.05-10-042 found that the use of non unit-specific contracts, also referred to as LD contracts, was not compatible with the physical nature of the RA obligation and should be eliminated for RA purposes. The Commission provided a three-year transition period (2006-2008) for phasing out authorization to count the associated capacity for most commercial contracts, and it allowed the ongoing use of LD contracts with the California Department of Water Resources. To the extent that LSEs have used LD contracts to meet their RA obligations, the program has not assured the availability of specific units of physical generation capacity to the CAISO as needed for peak loads and reserves.

counting rules were recently reviewed in R.08-01-025 and the PRM is being reviewed in R.08-04-012. D.09-06-028 provided for the issuance of another rulemaking in 2009 to further review technical aspects of the RA program. Finally, development of a standardized capacity product has been long proposed as a necessary improvement to facilitate the trading of capacity, but such a product was only recently approved by the FERC and has yet to be fully integrated into the RA program.[12]

Also affecting our assessment of the program's outcomes are policies and practices external to the narrowly-defined RA program that may impact achievement of the objectives. These include the Commission's long-term procurement planning (LTPP) process, which focuses on investment planning by and for the IOUs, as well as the Renewables Portfolio Standard (RPS), which promotes investment in renewable resources. The resource development that California has seen in recent years may be, in significant part, attributable to these programs.

Although there are challenges to assessing the program based on its actual performance, the Track 2 record enables us to draw several conclusions about the program's outlook for success in meeting its objectives and to identify ways in which the program might be improved. The Staff Report makes several observations about the current program as well as the BTG proposal (described later herein; see Section 3.5.1.2), which it describes as a "… continuation of the status quo with regard to the current RA program." (Staff Report at 50.) As we assess the current program, it is reasonable to consider the staff's analysis as well as parties' comments regarding the BTG approach. Recommendation 2 in the

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[12] *Order Accepting in Part and Rejecting in Part Tariff Revisions Subject to Modification*, 127 FERC ¶ 61,298, issued June 26, 2009 in FERC Docket No. ER09-1064-000.

Staff Report is also a variation of the current program, and comments on whether that option meets the objectives may be applicable to the current program as well.

In Sections 3.4.2 through 3.4.5 we review the Staff Report's analyses and parties' comments with respect to how the current program is meeting the four program objectives discussed earlier. Then, in Section 3.4.6, we draw conclusions regarding the program's performance and what improvements might be needed or desirable.

3.4.2. The Reliability Objective

The Staff Report finds that the current program does not promote price transparency. According to staff, greater price transparency could be beneficial by indicating locational and operational needs for appropriate forward investment. In addition to this potential impediment to investment, staff finds that because the program requires only a short-term commitment of capacity, resource developers face uncertainty that prices will remain high enough to give a reasonable prospect for recovery of investment.

Notwithstanding these concerns, staff concludes that overall, the current program and the BTG proposal meet the reliability objective:

> The [BTG] proposal ensures reliability. As a fundamental continuation of the existing RA program, an assessment of reliability associated with the [BTG] proposal need only examine the current state of reliability. By most measures the state is resource adequate under the current program; where and when appropriate, reliability mechanisms have functioned as intended and resources have been available to ensure grid reliability. (Staff Report at 51.)
>
> The BTG proposal enables new generation. New generation comes online under the BTG proposal via LSE bilateral contracting or via a mechanism associated with the Commission's LTPP proceeding. In the LTPP proceeding IOUs can be ordered to procure new

> generation and share the costs of that generation with all benefiting LSEs. (*Id*.)

The comments reflect agreement among some parties with the staff's assessment of the program's reliability performance, while other parties challenge the staff's conclusions. Criticizing the short-term focus of the BTG proposal, and by implication that of the current program, CFCMA states the following:

> By failing to give sufficient warning of impending potential reliability problems, the BTG proposal necessarily supposes that there is always something someone can do to fix a problem in short order. This supposition could easily prove false, leaving the system with a glaring reliability weakness that a more comprehensive, forward-looking design such as CFCM could have addressed in a timely, cost-effective manner. (CFCMA Comments at 43.)

Commenting on Recommendation 2 in the Staff Report, IEP contends that a forward commitment of at least four years is needed to allow time for resources to be planned, permitted, and constructed and for transmission upgrades to be completed. IEP states that "[f]ew would argue that the existing one-year horizon of the RA program is effective in stimulating investment in new capacity." (IEP Comments at 29.) Noting the requirement of Section 380 that the RA program must ensure and not merely enable investment in new generation, PG&E asserts that the one-year time horizon of the current program is insufficient to accomplish this purpose.

3.4.3. The Least Cost Objective

3.4.3.1. Price Discrimination

The Staff Report finds that the current bilateral approach allows for price discrimination that avoids windfalls to current generators while facilitating investment in new generation. Further addressing price discrimination in its analysis of the BTG approach, the staff states:

> The BTG proposal is generally consistent with least cost principles but raises some concerns with regard to overall cost. In the current market existing generation is paid significantly less than new generation. The overall program cost associated with the BTG proposal is therefore less than a market where all generation is paid the same price. Some parties postulate that generation developers will/have adjusted their bids for long term contracts to capture generation lifetime costs since revenue after the initial long term contract expires is uncertain. (Staff Report at 52.)

BTG concurs that the bilateral contracting approach allows for price discrimination between new and existing capacity resources that benefits ratepayers, although it disputes the contention that developers will adjust their bids to capture lifetime costs. BTG estimates that, compared to a centralized approach where all qualifying capacity would receive capacity payments based on the cost of new generation, the bilateral approach saves ratepayers approximately $1 billion annually. PG&E sees the ability to limit windfalls associated with new-entry pricing as a cost-saving benefit of the bilateral contracting approach. Noting that the BTG approach closely follows current practice, CUE explains the argument in favor of promoting discrimination as follows:

> On the key metric of providing least cost electrical service, the BTG approach allows payments to existing generation to be lower than payments to new generation, and thus lower than payments would be under any of the centralized capacity market approaches. [Footnote omitted.] This must be recognized as a major virtue of this approach. (CUE Comments at 6-7.)

Several parties see price discrimination between new and existing resources as a negative aspect of the bilateral approach. Calpine faults the "…severe under-compensation of existing generators compared to new resources that have been developed by or for the IOUs…." (Calpine Comments at 3.) CFCMA contends that even if the Commission seeks as a matter of policy to promote such a two-tiered pricing regime, "the price discrimination contemplated in the BTG proposal cannot persist since no rational seller will offer capacity at a sharp discount to market." (CFCMA Comments at 19.) CFCMA goes on to contend that "[t]here is neither theory nor evidence to support the belief that using a bilateral approach will sustain price discrimination between existing and new resources, which is responsible for most of the alleged cost savings of the BTG plan." (*Id*. at 29.)

Addressing Recommendation 2 in the Staff Report and its reliance on price discrimination, Dynegy agrees with CFCMA's observation that it is unlikely that suppliers of existing capacity will simply accept a discount for providing the same service as owners of new capacity, especially if the price of capacity becomes more transparent. Dynegy also agrees with IEP's concern that opaque pricing would be needed to sustain any gains that might be yielded by price discrimination. Finally, Dynegy notes that "new" generation eventually becomes "existing capacity." According to Dynegy, merchants seeking to invest in California will account for any discriminatory treatment and include a risk premium in their bids or invest elsewhere.

The CAISO addresses the price discrimination issue in the context of defending the proposed centralized capacity auction approach against assertions that it would add significantly to consumer costs. According to the CAISO, the argument in favor of fostering discrimination as a cost-saving measure is flawed:

> First, the argument erroneously assumes that there is no consumer benefit to paying the clearing price to all capacity that clears, even if it enables existing resources to earn a return above their costs of staying in business. Although the approach advocated by these parties might appear cost-effective in the short run, it can easily result in an excessive amount of retirements by facilities that are unable to earn enough to invest in environmental upgrades or

repowering. A good illustration of this is "once-through cooling," a power plant design feature that applies to roughly 21,000 [megawatts (MW)] of installed capacity within the CAISO balancing authority area and has recently been targeted as having significant adverse environmental impacts. Under a [centralized capacity market (CCM)] where such capacity can earn the CCM clearing price, owners of these resources will be able to make economically efficient decisions whether to cease operating or invest in environmental upgrades in response to any policy initiatives to eliminate once-through cooling. Under the proposed bilateral approach to avoid paying a market clearing capacity price, these existing resources may have little or no choice but to exit the market, removing a potentially large amount of supply capacity which tends to be concentrated in load pockets and which could, if their revenues justified the investment, remain in operation with less ultimate environmental impact than developing alternative supply capacity for these areas. (CAISO Reply Comments at 14.)

Second, the argument assumes that it is feasible to realize substantial short-term consumer savings by paying existing resources less than new investment. This argument is analogous to the well-refuted argument that a "pay-as-bid" regime is cheaper for buyers than a "pay-the-market-clearing-price" regime. It has been well established that in a pay-as-bid regime, bidding behavior changes as suppliers try to estimate what the market clearing price would be and incorporate that into their supply offers. This outcome will extend to the markets for environmental compliance. If there are no transparent market price signals on which suppliers can base their estimates, their estimates will be highly diverse, with no obvious relationship to each resource's underlying cost structure, and thus will blur any cost basis to a comparison among their offer prices. As a result, the purported cost savings to consumers will be eroded, and the process will not necessarily choose the most efficient resources. In contrast, a competitive market clearing price regime is known to provide strong incentives to suppliers to bid their lowest acceptable price to maximize their chance of being selected when they are assured that they will earn the clearing price. Alternatively, if a potential investor knows that a new facility will start to receive a much lower capacity price once its status changes from "new" to

> "existing" it will incorporate that expectation into its offer price prior to committing to constructing the new resource. (*Id*. at 14-15.)

The CAISO sees an additional flaw in the argument for promoting price discrimination through an opaque pricing regime. According to the CAISO, the absence of a transparent market provides opportunities for third-party intermediaries to capture a significant share of the consumer and producer surpluses that the bilateral proponents assert will be realized as savings to consumers.[13]

3.4.3.2. Multi-Year Forward Commitment

The current program's lack of a multi-year forward commitment of capacity is another of the more significant and controversial matters in this proceeding. We have already noted comments regarding the implications of the short-term focus of the current program for reliability. Some parties see the short-term nature of the current RA obligation as a major RA program shortcoming that also adds to costs. The CAISO believes that:

> The [RA] framework should provide for a multi-year forward review, or showing, of the capacity that is actually committed to serve CAISO control area needs for the target delivery year. The absence of a demonstration of actual capacity commitments would

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[13] The CAISO explains and expands upon this assertion as follows:

> When centrally-clearing transparent markets are not available such intermediaries provide valuable "market-maker" services by reducing transaction costs for buyers and sellers, but they do so less efficiently than a CCM because each such intermediary controls only a portion of the market. Thus the bilateral versus CCM distinction can be viewed as a distinction between non-transparent, less efficient markets in which consumer and producer surpluses are captured by private market makers, versus transparent efficient markets where the surpluses are realized by the buyers and sellers. The result is that the purported cost savings from adopting a bilateral approach rather than a CCM has little chance of being realized by the consumers to any great extent. (CAISO reply comments at 16.)

> add unnecessary uncertainty to decision-making processes, both private and by central authorities, on the timing and optimal characteristics of investments in new infrastructure. (Staff Report at 23; CAISO Comments at 8-9.)

Contending that the question of a multi-year forward commitment is a key, threshold decision that should not be deferred to a later proceeding, the CAISO contends that a multi-year forward structure (1) will allow competition between existing and new resources, (2) will encompass decisions to repower or retire existing generation and to invest in new DR capacity, and (3) can be linked explicitly to decisions whether to upgrade transmission into constrained areas. As to the third point, the CAISO sees the creation of an environment where specific transmission upgrade projects could compete transparently against new supply resources (including DR) as essential for meeting needs through the most cost-effective alternatives. CFCMA takes a similar position, contending that a multi-year forward capacity commitment would enable integration of generation and transmission planning, orderly retirement of existing resources, and advance notice for backstop procurement.

AReM, in contrast, sees the lack of a multi-year forward commitment as a positive, cost-saving aspect of the current program: "Establishing a multi-year forward obligation for LSEs will entail lengthy proceedings and development of extensive new regulations that would be complex and costly to implement." (AReM Comment at 15.)

3.4.3.3. Other Least Cost Considerations

Staff and commenting parties addressed several other factors affecting or related to the least cost objective. These are summarized below:

- Staff finds that LSEs and generation owners alike encounter the possibility of asymmetric information under the current program. According to staff, this could lead to inefficient procurement because of the time required to locate buyers and sellers and because buyers and sellers in some situations are unable to benchmark their bids against others.

- Asymmetric information can also exacerbate monopsony or monopoly power, according to staff. Similarly, the CAISO finds that with a bilateral approach to RA procurement, supplier market power would be less transparent and hence less amenable to mitigation via standard approaches used in centralized markets.
- The Staff Report observes that, compared to the current program, the better market information that would be provided by the electronic bulletin board envisioned in the BTG proposal should narrow the range of prices for existing generation. BTG agrees that a fungible, tradable capacity product as well as an electronic bulletin board are needed. Staff finds that to the extent that actual prices are different than what market clearing prices would be in a more transparent market, costs to ratepayers may increase or decrease.
- PG&E contends that because the bilateral contracting approach relies on long-term contracts with creditworthy counterparties, customers are not forced to pay new resources a risk premium for market failure.
- PG&E notes that the bilateral approach relies on continued oversight of this Commission and its authority to safeguard customer costs by ensuring that least cost principles are applied to procurement.
- The CAISO notes that there is no clearly defined, permanent backstop procurement mechanism under the current program. The CAISO further notes that such a mechanism would, by default, become the centralized capacity pricing mechanism that sets a benchmark price for bilateral contracting for RA capacity. Also concerned about backstop procurement, IEP contends that neither the RCST nor its replacement, the ICPM, can be expected to function as stable backstop mechanisms. PG&E also notes that a robust and clearly defined backstop is essential for reliability, and that a robust trigger mechanism is important to forestall unplanned regulatory intervention, unduly expensive last-minute procurement, and market disruption.

- Staff finds that the current program imposes administrative obligations on LSEs and on the agencies administering the program, including the CEC and CAISO as well as the Energy Division. A survey of the agency personnel found that the agencies dedicate a substantial amount of time and resources to the program each month. Staff states that it lacks data to assess the administrative burden that the program imposes on LSEs.

We note that the CAISO's Department of Market Monitoring (DMM) has recognized the substantial benefits that the RA program has had in reducing CAISO out of market capacity procurement. The DMM's Market Issue & Performance 2008 Annual Report (DMM 2008 Report) observed that "[t]he implementation of the RA program in June 2006 has significantly reduced reliance on the FERC-directed Must-Offer Obligation." (DMM Report at 6.9.) Annual backstop payments declined approximately 86.92 percent between 2007 (approximately $26 million RCST payments) and 2008 (approximately $3.4 million RCST and TCPM payments combined). (DMM Report at Executive Summary p. 3; see also table 6.6.) Costs for CAISO Reliability Must-Run contracts also shrank 83 percent between 2006 and 2008 as a result of the introduction of the Local RA procurement requirements. (DMM Report at Sec. 6.13; see also table 6.3.)

3.4.4. The Equitable Cost Allocation Objective

Relatively few comments addressed whether or how well the current program is meeting the equitable allocation objective. CFCMA states concern regarding a "cost allocation overhang" associated with IOU backstop procurement that it believes will occur under the status quo. Defending the imposition of a multi-year forward procurement obligation on all LSEs, including ESPs as well as IOUs, and by implication finding fault with the current program's lack of such an obligation, CUE argues as follows:

> In a capital-intensive industry with long lead times for construction, electric utility participants who are not prepared to make multi-year resource commitments are free-riding on their competitors. Unlike most other industries, there is no way to cut off customers of individual sellers in the event of a reliability shortfall. Outages cannot be rotated that way. Thus, it is important that all market participants be prepared to shoulder their share of long-term reliability requirements, and a market structure that penalizes those who are unwilling to do so is just and proper. (CUE Comments at 7-8.)

3.4.5. The Program and Policy Coordination Objective

3.4.5.1. Competitive Wholesale Markets

The Staff Report finds that a limited amount of merchant generation has entered the market under the current RA program, but that is generally limited to smaller resources. According to staff, "[i]t is unlikely that merchant generation would enter the market absent a IOU long term contract if the Commission continues to authorize IOUs to meet system need through long term contracts supported by all benefiting customers." (Staff Report at 52.) Staff believes that to the extent that IOUs are contracting for most or all new generation, the incentives for other LSEs and independent developers to invest in the new resources may be reduced.

A number of parties emphasize and expand upon the staff's findings that the current program relies on IOU investment and does not promote or enable entry by merchant generation. CFCMA contends that the existing RA system results in IOUs supporting all new build. CFCMA goes on to state that "the only way that the BTG design enables new generation is through mandated IOU purchases or builds, hardly an outcome that can be considered to be a successful market design, and one that will forever thwart the development of competitive markets for consumers." (CFCMA Comments at 44.) Complete Energy takes the position that continuation of the status quo, including the BTG proposal and Recommendation 2 in the Staff Report, will not further the Commission's desire to see merchant generation develop in California. Constellation finds that the bilateral approach, which relies on regulatory intervention through the LTPP process, and where all new generation is secured through utility-backed contracts or direct utility build projects, is not sufficiently robust to support competition. IEP notes that when the Commission perceived that additional capacity was needed to maintain reliability following the heat storm of 2006, the first impulse was to authorize construction of utility-owned generation. Commenting on the Staff Report's proposal to modify the BTG proposal, Sempra Global contends that the short-term bilateral approach tends to default to IOU procurement and has the effect of undercutting competitive wholesale generation markets in California. Dynegy asserts that the current process "seems only to have all but dried up new merchant investment in California and reinvigorated a rush toward expensive utility self-build projects." (Dynegy Reply Comments at 2.) Mirant takes the argument even further than the other parties. According to Mirant's view, market-based investment in new generation simply will not occur as long as the prospect for continued ratepayer-funded investment in generation remains.

3.4.5.2. Competitive Retail Markets

The Staff Report finds that the BTG proposal generally enables direct access and that the BTG proposal is not in conflict with the current direct access program or the reopening of direct access.

AReM emphasizes its concern regarding any backstop mechanism in which IOUs procure on behalf of direct access customers. AReM believes that such procurement impairs retail competition.

CFCMA takes the position that competitive wholesale and retail markets go hand in hand. According to CFCMA, without a robust merchant supply sector, which CFCMA contends would not exist under the bilateral approach, the direct access retail market will wither.

3.4.5.3. Environmental Goals

The Staff Report finds that the BTG proposal supports the Commission's environmental policies. According to the staff, by having the IOUs build generation for system needs, through the LTPP process the Commission can ensure that changes in environmental rules are incorporated into the decision-making process. PG&E has a similar view. As PG&E explains, the bilateral approach allows continued Commission oversight to ensure that the resources procured to meet RA obligations will be consistent with the Commission's environmental and other policy objectives. CUE believes that the current approach "is facilitating the transition toward renewable resource use which will need to continue for the rest of the 21st century." (CUE Comments at 2.)

3.4.6. Discussion: Assessment of the Current RA Program

3.4.6.1. Forward Investment

Since its inception in 2006, the RA program has generally yielded the availability of resources that the CAISO needs to reliably operate the transmission grid. However, it is apparent that this early success is based largely on LSEs meeting their RA obligations by procuring from the pre-existing fleet of generation resources. The more important reliability question now is whether the program will achieve adequate investment in new generation and retention of existing resources that are economic and needed.

The resource development that California has seen in recent years cannot be attributed to significant merchant investment that was prompted by the RA program as narrowly defined. Instead, as the Staff Report and the comments make clear, this Commission has been relying on the IOUs and the LTPP process to ensure that sufficient resources are being developed for future needs. Moreover, as alluded to earlier, it is reasonable to conclude that California's aggressive RPS policy is responsible for a significant portion of the resource development that has occurred in recent years. However, as TURN explains in its comments on the ALJ's proposed decision, we are not constrained to consider the RA program on a stand-alone basis, separate from the LTPP and RPS processes. On the contrary, both Section 380(g) and recently enacted Section 365.1(c)(2) anticipate forward investment by IOUs because they provide for a mechanism by which RA costs incurred by IOUs for system reliability may be passed on to the IOUs' bundled and unbundled service customers.

Arguably, the LTPP process applies only to IOUs, and does not treat IOUs and ESPs (or CCAs) alike.[14] This could be viewed as being inconsistent with Section 380(e)'s directives to implement and enforce RA requirements in a nondiscriminatory manner and to subject each LSE to the same RA requirements. However, upon reading the statutory provisions together, we reject any such conclusion for the reason noted above. Accordingly, we find that while the narrowly defined RA program may not have been meeting the primary

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[14] On the other hand, through the Cost Allocation Mechanism established by D.06-07-029, IOUs that make certain types of forward commitments may, in defined circumstances, pass a portion of the procurement costs to non-IOU LSEs. Thus, in those circumstances, the LTPP process is indirectly applicable to all LSEs.

reliability objective of facilitating investment in new generation, forward investment is being addressed by Commission programs in a manner that is consistent with Section 380.

3.4.6.2. Multi-Year Forward Commitment

The IOUs and the CAISO, among other parties, maintain that a multi-year forward commitment should be added to the RA program for both reliability and cost reasons, while AReM, BTG, and Constellation find such a commitment to be unnecessary.

A multi-year forward commitment would have the potential to provide important reliability benefits. It would provide advance knowledge of impending reliability problems, years ahead of delivery, allowing planners to address those problems in a timely, cost-effective manner. Additionally, a multi-year forward commitment would be expected to stimulate merchant generator investment, supporting our policy not to rely solely on Commission-directed forward procurement by IOUs to provide the investment needed for new generation. Further, as the CAISO points out, a multi-year forward commitment would promote competition between new and existing resources as well as competition between transmission upgrades and supply additions. Such competition could yield more cost-effective outcomes. Having generation investment commitments made years in advance should also promote more cost-effective backstop procurement decisions. Finally, as CUE notes, a multi-year forward RA commitment applicable to all LSEs could be an effective way to ensure that all market participants shoulder the burden of promoting investment, which in turn would help to achieve the equitable allocation objective.

On the other hand, we also find there are significant reasons not to proceed with a multi-year forward procurement mandate at this time. As AReM argues, a multi-year forward commitment may not be necessary because three new programs, including the current RA program, are expected to encourage new generation development. The other two programs are the Locational Marginal Pricing component of the CAISO's MRTU process and the RPS program. AReM also contends that as a practical matter, LSEs will need to make long-term commitments even in the absence of a regulatory obligation. Constellation makes similar points, arguing that a stable market environment with transparent price signals will provide adequate incentives for investment. We find merit in these arguments. The RA program is new, and we should recognize the possibility that the year-ahead procurement obligation will provide adequate incentive for merchant development. Finally, we note AReM's contention that a multi-year forward obligation is incompatible with a competitive retail market. BTG takes a similar position. We return to this topic later in this decision, noting here only that this is a very significant concern.

We conclude that the addition of a long-term procurement obligation is a regulatory tool that could potentially benefit the RA program with respect to the reliability, cost, and equitable allocation objectives. At the same time, it is too soon to conclude that many, or most, of the benefits will not be achieved under the current year-ahead approach. As discussed later in this decision, we must weigh these considerations against the potential impact of a multi-year forward commitment on competitive markets.

3.4.6.3. Market Transparency and Efficiency

While there is significant controversy regarding the form that the capacity market should take, there is broad agreement that some improvement to the current market structure is needed. As a general matter, we find that the RA capacity market would better promote investment, and do so more cost-effectively, if greater price transparency and symmetry of information were available to market participants. Among other things, as the staff notes, such a development could help to reduce transaction costs as well as mitigate market power. An electronic bulletin board platform with coordinated communication and centralized listing would allow more efficient matching of buyers and sellers in bilateral transactions. A platform that includes the functions of a credit and clearing mechanism along with tracking and tagging of sales could facilitate compliance review and minimize inefficient reporting. We find that an electronic bulletin board with appropriate public disclosure of price and trading information is the minimum improvement necessary to facilitate trading and promote greater liquidity. Whether this approach or a more centralized auction approach would better meet RA program objectives is addressed later in this decision.

3.4.6.4. The Role of Price Discrimination

The record yields a mixed picture with respect to whether the bilateral trading approach associated with the current RA program (as well as several of the alternative proposals before us) enables a form of price discrimination that is beneficial to ratepayers. On the one hand, there is BTG's estimate that the bilateral approach allows ratepayers to save $1 billion annually by paying existing generation owners less than the cost of new generation. While this figure is clearly more illustrative of the order of magnitude of potential ratepayer savings than it is a precise calculation, there could be significant procurement-related savings for ratepayers, and it might be worthwhile to pursue such savings, if such reduced payments are achievable and sustainable over time.

On the other hand, there is reason to conclude that sustaining such price discrimination over time would be unlikely, and that it would be at odds with our primary objective to achieve investment needed for reliability. In a bilateral trading regime, owners of existing capacity will attempt to compensate for the prospect of reduced capacity payments by adjusting their bids accordingly. To the extent they are successful in such attempts, any ratepayer benefits would be diminished or eliminated. Also, as the CAISO observes, third-party intermediaries will seek opportunities to capture a share of the surpluses, which would further diminish consumer savings. And, as IEP and other parties have noted, price discrimination between resource classes would be possible only to the extent that the market is opaque, yet we have decided to pursue greater price transparency and symmetry of information available to market participants.

Moreover, savings to ratepayers that result from paying less than new entry cost to existing resources may be short-term and come at a long-term cost. Investors in potential new generation projects will recognize that such resources eventually become "existing generation" and factor that into their investment and bidding decisions. A policy of promoting price discrimination between new and existing could thus dampen incentives for new investment and/or cause increased bids. Such a policy could also lead to unnecessary or inappropriate excess retirements of existing resources that are otherwise economic, including resources that are candidates for repowering and environmental upgrades.

3.4.6.5. Backstop Procurement

As the CAISO has noted, its RCST and ICPM processes cannot be expected to function as stable backstop mechanisms. While it is our policy to design the RA program in a way that minimizes the need for backstop procurement, we concur the absence of a durable backstop mechanism is another shortcoming of the current program that jeopardizes the reliability and cost-effectiveness objectives.

3.4.6.6. Administrative Burden

Staff observes that the current RA program imposes administrative burdens on LSEs and agencies. However, nothing in the record leads us to conclude that administrative costs are unreasonable for the involved agencies. Similarly, there is no evidence that the current program imposes unreasonable administrative costs on LSEs.

3.4.6.7. Equitable Cost Allocation

We noted earlier that the record does not disclose broad concern among parties that the current program is failing to meet the objective of equitable cost allocation and avoidance of cost shifting. This may reflect the fact that the RA program imposes like procurement and reporting obligations on all LSEs.

The current RA program depends on IOUs and the LTPP process to provide forward investment. To the extent that existing mechanisms, such as the Cost Allocation Mechanism adopted in D.06-07-029, equitably allocate IOUs' investment costs among all LSEs, the equitable allocation objective is met.

3.4.6.8. Program and Policy Coordination

This Commission has stated its policy preference for a wholesale generation market in California that provides merchant generation firms an opportunity to invest and compete with a reasonable expectation that competition from ratepayer-backed utility investment will not undermine their investment decisions.[15] We recognize the concerns of several parties that the

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[15] For example, the Commission stated in an LTPP decision that "[w]e do weigh heavily in favor of a competitive market first approach …" (D.07-12-052 at 201.) It stated in the same decision that "[t]he Commission is committed to developing a functional competitive energy market in California …" (*Id*. at 210.) The Commission's policy regarding IOU ownership is actually more

current RA program does not adequately promote this policy because it relies too heavily on IOU procurement (including utility-owned generation and long-term contracts) to ensure that investment in non-renewable resources needed for long-term reliability occurs. However, as noted earlier, Sections 365.1(c)(2) and 380(g) anticipate an IOU procurement role for resource adequacy. As we evaluate the options before us in Section 3.5 of this decision, we will seek opportunities to support competitive wholesale markets while ensuring that the primary goals for resource adequacy are met.

We do not find that the current RA program unduly interferes with or undermines the Commission's policy for competitive retail markets. By law and by design, the RA program should be neutral with respect to the treatment of the classes of LSEs.

Finally, we do not find that the current RA program thwarts achievement of the Commission's and the State's environmental goals, including the RPS program. In fact, by maintaining Commission jurisdiction with respect to LSE-based procurement, the bilateral approach ensures that the Commission is authorized to ensure that environmental policies are being met.

3.4.6.9. Summary

To summarize the foregoing discussion regarding our assessment of the current RA program, we make the following conclusions about its strengths and shortcomings.

- The RA program is meeting the short-term reliability objective of making installed capacity available to the CAISO at times and in places needed for reliable operation of the transmission grid.

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nuanced. In particular, the Commission has discussed circumstances under which utility ownership of renewable resources would be permissible or encouraged. (D.08-02-008 at 32-35.)

- The long-term reliability objective of facilitating development of new generating capacity is being addressed by the RA program in conjunction with the Commission's LTPP and RPS programs in a manner that is consistent with Section 380.
- A multi-year forward commitment could potentially result in better achievement of the reliability, least cost, and equitable allocation objectives, but it is premature to conclude that many if not most of these benefits are not achievable under the current RA program.
- The current bilateral contracting approach may, on a short run basis, enable price discrimination between new and existing resources that may be consistent with the least cost objective. However, this has not been shown to be sustainable on a long-term basis. Among other things, it relies upon a lack of market transparency. Also, a policy intended to hold down prices for existing generation is at odds with the objective of retaining existing generation capacity that is economic and needed, and it may impair investment in new generation.
- Greater price transparency and symmetry of information availability to market participants is needed to promote appropriate investment decisions, mitigate market power, and reduce transaction costs. At a minimum, an electronic bulletin board or equivalent mechanism with appropriate disclosure of price and other market information is needed.
- A more durable backstop procurement mechanism is needed to complement the RA program.
- While some parties are concerned that the current RA program does not adequately promote the policy of a competitive wholesale generation market in which merchant generation owners compete with IOUs, in other respects, the program generally supports Commission and State policies such as competitive retail markets and environmental policies.

In the following sections we review the options before us for improving the RA program and inquire into whether the program objectives can be met more effectively.

3.5. Review of Program Options

The Staff Report identified the following principal types of mechanisms by which capacity needs may be met:[16]

- Bilateral arrangements between LSEs and suppliers, for both new investment and existing capacity.
- A bulletin board that allows posting of offers to buy and sell capacity, which provides an information resource to support bilateral arrangements.
- A central auction market for trading capacity.
- Backstop procurement by the CAISO to fill any identified procurement gaps left open by the previous mechanisms such as RMR, RCST, and ICPM.

Staff notes that two of these mechanisms, bilateral procurement and CAISO backstop procurement, are used in the current RA framework and that a bulletin board and a central auction market have been proposed in this proceeding. We find there are two broad categories of proposals for resource adequacy in this proceeding: (1) those that involve continuation of the current RA framework with its reliance on bilateral procurement, either in its current form or with modifications such as a bulletin board and a multi-year forward obligation; and (2) those that would replace the current RA framework with a mechanism that includes a centralized capacity auction administered by the CAISO. Sections 3.5.1 and 3.5.2 provide an overview of the eleven principal options under these categories—five bilateral and six centralized auction options.

[16] Staff Report at 45. In addition to these four mechanisms, the Staff Report noted that forward ancillary services procurement mechanisms as well as the CAISO's Day-Ahead and Real-Time and ancillary services markets represent additional options for meeting capacity needs. However, these mechanisms were only briefly discussed in the Track 2 workshops and were not fully developed in the Track 2 record.

We follow the Staff Report's convention of focusing on the options that were discussed in workshops and post-workshop comments.

3.5.1. Bilateral Procurement Options

3.5.1.1. Maintain the Status Quo

Although the purpose of this proceeding is to explore whether there are alternatives to the status quo that would better achieve the RA program objectives, a comprehensive review of the options before the Commission necessarily includes the option of continuing the status quo. Unless we can find either a package of modifications or an entirely new formulation that is superior to the current program, we would maintain the status quo notwithstanding its shortcomings. We note that maintaining the status quo includes continuing the evolutionary, incremental approach to program refinement that has been observed since the blueprint for the program was first adopted in 2004.

3.5.1.2. BTG Proposal

The BTG proposal builds off the current RA program and adds provisions for an electronic bulletin board to facilitate market liquidity and transparency along with a standardized and tradable capacity product with generator obligations placed in the CAISO tariff. The IOU-based backstop procurement and cost allocation mechanism adopted in D.06-07-029 would be continued with modifications to include more locationally targeted investment and to allow LSEs to opt out of such backstop procurement through demonstrated commitments to new generation on a multi-year forward basis.

While the BTG proposal is presented as being consistent with an eventual transition to an energy-only paradigm with an appropriate scarcity pricing mechanism, that end-state is not an integral component of the actual BTG proposal. Instead, BTG envisions that offer caps in the CAISO-administered spot energy and ancillary services markets would be allowed to gradually increase. Over time, rising energy and ancillary services prices would signal the need for investment in new generation, and the need for a separate capacity product would diminish.

Since we have defined the status quo to encompass continued evolution and refinement of the RA program, the BTG proposal (not including the energy-only end-state) can be seen as a status quo proposal.

3.5.1.3. Staff Recommendation 2

For this option, staff recommends what it calls minor adjustments to the current program to bring greater price transparency and contracting efficiency. These include an electronic bulletin board, a standard set of generator obligations, and a collaborative forward assessment of capacity need with a multi-year horizon. A key feature of Staff Recommendation 2, and its most important distinction from the BTG proposal, is its provision to study whether to extend the current year-ahead RA obligation to a multi-year forward obligation. Enactment and implementation of a multi-year forward obligation would be left to a future proceeding. Thus, like the BTG proposal, Staff Recommendation 2 is essentially a status quo proposal.

3.5.1.4. PG&E's Proposed Multi-Year Bilateral Approach

PG&E's bilateral proposal takes a more aggressive approach to modifying the current program while preserving the essential element of mandatory forward LSE procurement through bilateral transactions, based on LSE-specific load forecasts. Two key features of this proposal, for which PG&E provides a broad outline with the expectation that further workshops would be needed to finalize details, are (1) implementing a standardized, tradable capacity product and associated Resource Adequacy Registry and (2) replacing the current program's year-ahead and month-ahead demonstrations to the Commission with five-, four-, and three-year-and month-ahead demonstrations made by entering procurement in the Resource Adequacy Registry. An LSE's initial showing would be at least 80% of the load assessment for each LSE, rising to 100% by the three-year-ahead showing. Each five-year cycle would begin with a comprehensive forward assessment of the state's needs. PG&E envisions that the CEC, the Commission, the CAISO, and local regulatory authorities, with full stakeholder participation, would develop the assessment of the sufficiency, reliability, competitiveness, environmental, and performance needs of the system covering a five- to ten-year study period. LSE procurement deficiencies would be addressed by CAISO backstop procurement of existing resources and alternative backstop mechanisms for new resources. PG&E suggests without elaboration that legislative changes would be needed to ensure that equivalent requirements are applicable to non-jurisdictional entities.

3.5.1.5. Aglet's Proposal for a Physical Call Option Market

Aglet proposes to maintain existing RA requirements and add new components to them. Aglet's main proposal is the institution of a Commission–established Physical Call Option Market (PCOM) that would be overseen by the Commission's Energy Division using a third-party vendor.[17] Aglet sees the PCOM as a complement to the existing RA program, and LSE participation would be voluntary. An LSE that elects to participate could meet its procurement obligation entirely or partially through the PCOM. The

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[17] In comments on the proposed decision, Aglet notes that under its proposal the third-party vendor, not the Energy Division, would function as the administrator of the PCOM. We believe there would need to be a continuing oversight and monitoring role for the Energy Division under Aglet's proposal.

Commission would retain authority to allow IOUs to participate in the PCOM. Funding for operation of the PCOM would come from fees charged to buyers and sellers in the market.

Aglet also proposes that each LSE be required to enter into 10-year contracts with new or repowered generation that provide for expected energy output equal to 3% or more of the LSE's annual retail sales. Additionally, Aglet proposes that LSEs be required to meet a three-year forward capacity commitment of RA resources. Similar to the current RA requirement, the three-year-ahead compliance showing would be for 90% of the requirement for May through September of each year.

3.5.2. CAISO-Administered Capacity Auction Options

3.5.2.1. Overview

Several proposals were made to move from the RA program's reliance on bilateral transactions between LSEs and suppliers of capacity to use of a centralized procurement mechanism that would be administered by the CAISO.[18] These CAISO-centered proposals were modeled, in part, on one or more of the three capacity market approaches that have been employed in the eastern United States by PJM Interconnection (PJM), ISO New England (ISO-NE), and the New York Independent System Operator (NYISO).[19]

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[18] In theory, an entity other than the CAISO could administer a centralized mechanism. As a practical matter, no viable alternative to CAISO administration of a centralized mechanism was identified or proposed.

[19] PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. ISO-NE is an RTO serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. NYISO operates New

In general, the centralized capacity auction proposals involve a shift from the requirement for LSE compliance showings to the Commission to some degree of mandatory LSE participation in the centralized auction. The Commission's primary role in ensuring resource adequacy would be limited to establishing (or participating in the establishment of) capacity needs assessments and issuing and enforcing regulations governing LSE participation in the CAISO auction mechanism. In essence, a substantial portion of California's RA program would become embodied in CAISO tariffs approved by the FERC.[20]

While these options have in common the feature of a CAISO-administered capacity auction, there are important variations among them. The variations include, but are not limited to, whether to include a multi-year forward component, impose floor and/or ceiling prices on the auction, employ an

York's bulk electricity grid, administers the state's wholesale electricity markets, and provides comprehensive reliability planning for the state's bulk electricity system.

[20] Although Section 380(a) provides that the *Commission* shall establish resource adequacy requirements for all LSEs, it is possible to interpret that transfer of primary responsibility for the RA program to the CAISO is authorized by Section 380(i), which provides that the Commission may consider a "centralized resource adequacy mechanism, among other options," in determining and authorizing the most efficient and equitable means of achieving the statutory objectives for resource adequacy. The number and specificity of criteria by which the Commission must evaluate and approve the IOUs' procurement plans, however, tends to weigh against this interpretation. Section 454.5, which applies to procurement of energy and any "electricity-related product[s]" such as capacity, provides that each IOU's procurement plan, submitted to the Commission for approval, must fulfill unmet resource needs with an increasing percent of renewable resources (Section 454.5(b)(9)(A)), create and maintain a diversified portfolio of energy and demand products (Section 454.5(b)(9)(B)), increase diversity of resource ownership and fuel supply in non-utility owned resources (Section 454.5(b)(9)(B)(11), and specify the Utility's risk management and price stability strategies and practices (Section 454.5(b)(10)). "The Commission shall review, and accept, modify, or reject each electrical corporation's procurement plan" based on the individual IOU's particular circumstances (Section 454.5(c)); and shall allow for prospective modification of an IOU's procurement plan (Section 454.5(e)).

administratively determined demand curve pricing mechanism, employ reconfiguration auctions, and provide for a peak energy rent (PER) deduction.[21]

3.5.2.2. CAISO's Proposal

The CAISO makes three principal recommendations. First, it recommends that the Commission establish an annual or biennial, multi-year forward assessment of RA capacity needs, to be performed as a collaborative effort by the Commission, the CEC, and the CAISO. This assessment would serve both to inform bilateral procurement by LSEs and to establish the demand in a centralized capacity market structure. As such, the assessment would need to address capacity needs at the system-wide level and in local capacity areas, as well as the generator performance characteristics needed to support reliable grid operation.

Next, the CAISO also recommends that the Commission adopt a centralized capacity market in lieu of the current bilateral approach. The market would include a primary auction to be conducted approximately four years prior to each delivery year followed by periodic reconfiguration auctions leading up to each delivery year. The CAISO believes that the centralized market will provide appropriate signals to investors when new infrastructure and resources are needed with sufficient lead time to allow that infrastructure to be built before reliability is compromised. The CAISO sees other advantages to this approach that include transparency of the market clearing prices at the system and local levels, integration of a natural backstop procurement mechanism through the reconfiguration auctions, and simplicity of clearing the market to meet the

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[21] The basic concept of a PER adjustment is to prevent excessive total payments to suppliers that receive both capacity payments and energy payments. A PER adjustment would act as an offset to capacity payments received by a supplier.

aggregate needs of all LSEs without needing to allocate exact RA requirements and costs to each individual LSE until the actual delivery month. Moreover, the CAISO believes, a centralized capacity market approach can more effectively build upon and complement (and be complemented by) the features of the CAISO's MRTU project. Finally, the CAISO believes that a centralized capacity market structure can be fully compatible with extensive bilateral procurement by LSEs under the regulatory oversight of the Commission or applicable local regulatory authority.

Third, the CAISO recommends that the Commission make the key, threshold decisions at this time necessary to establish a long-term RA framework based on a multi-year forward comprehensive assessment of resource needs and a multi-year forward centralized capacity market, but refrain from specifying many of the details of the market design. The CAISO submits that it would be premature for the Commission to specify many of the details of the centralized capacity market design. Thus, while the CAISO acknowledged the complexities of satisfying the highly specific resource preferences now embodied in state energy and environmental policy, it offered few specifics on how these might be addressed.

3.5.2.3. CFCMA's Proposal

CFCMA entitles its proposal the California Forward Capacity Market (CFCM). Using features from the PJM and ISO-NE markets as well as California-specific provisions, the CFCM has the following key elements, as described by CFCMA:

1. **State-determined RA targets.** Approximately five years prior to a Delivery Year,[22] the Commission, the CAISO, and the CEC would

[22] CFCMA defines "Delivery Year" as a 12-month period from May 1 to April 30 of the following year.

jointly establish capacity resource requirements statewide and for any relevant import-constrained areas of the state, as well as the capacity transfer limits of the transmission system.

2. **Resource qualification and capacity tags**. The CAISO qualifies potential capacity resources, including planned and existing generation, distributed generation, and other demand-side resources using non-preferential criteria that fairly balance certainty of supply and broad participation. The qualification process creates "capacity tags" that can be traded among market participants, either bilaterally or within the CFCM Auctions.

3. **A centralized, forward, locational capacity auction**. Approximately four years prior to a Delivery Year, the CAISO will conduct an auction to acquire capacity supply obligations from sufficient resources to meet the RA targets, subject to the transfer limits of the transmission system. All cleared resources will be eligible to receive the capacity clearing price of their physical location in the delivery year (i.e., they are paid a local or system capacity price, depending on their location and the identified capacity need of the grid).

4. **Performance standards**. The CFCM includes clear and effective performance standards, enforced through the CAISO tariff, on all capacity resources to provide a strong incentive for capacity resources to have high availability and sufficient energy, particularly during peak usage periods.

5. **Self-supply**. Any LSE may offer resources as price-takers in the auction, assuring that these resources will offset the LSE's capacity payment obligation. LSEs may not, however, opt out of the market, and self-supplied resources are subject to the same performance standards applied to other capacity resources.

6. **Market monitoring and offer mitigation**. The CAISO market monitor has clear enforcement powers to ensure that offers into the CFCM are not intended to inflate or suppress capacity clearing prices away from a competitive level, especially in import-constrained areas in which there are relatively few buyers and sellers.

7. **Backstop Auctions**. The CFCM design is robust enough that sufficient market-based capacity should be secured by the CFCM

> auctions. In the unusual event that additional resources are required, the design includes provisions for backstop process by the CAISO, either by deferring acquisition or through a separate auction process.

The CFCM auction would use sealed bids. With certain exceptions, offer prices for existing supply could not exceed 60% of the administratively determined net capacity cost of new entry (Net CONE). Offer prices from any resource could not exceed two times Net CONE. In addition, to address investor risk and consumer rate shock concerns due to price volatility, capacity payments would, with certain exceptions, be bounded between 60% and 140% of the then-current estimate of Net CONE. The CFCM would also include annual reconfiguration auctions based on adjusted planning assumptions. The CFCM proposal includes a settlement procedure whereby for each month of the Delivery Year, the CAISO (1) pays each resource with a capacity supply obligation an amount equal to the product of the quantity of the obligation, the associated capacity clearing price, and a monthly scaling factor; and (2) charges each LSE its load-weighted average of the total capacity cost secured through the CFCM.

3.5.2.4. Constellation's Proposal

Constellation entitles its proposal the California Capacity Infrastructure Model (Cal CIM). Described as being similar to the NYISO approach, its central features are a forward, administratively determined demand curve pricing mechanism and month-ahead compliance demonstrations by LSEs. The demand curve would incorporate estimates of CONE and PER deductions reflecting estimates of the overall level of revenue achievable in the energy market. With this approach, Constellation intends to support but not require forward bilateral procurement by LSEs. Constellation describes the mechanics of the Cal CIM demand curve approach as follows:

- Step 1: Three years in advance of the first monthly compliance period, the CAISO, working cooperatively with the Commission and CEC, publishes the aggregate system and local resource adequacy requirement (RAR) for that forward period.
- Step 2: Three years in advance of the first monthly compliance period, the demand curve pricing is established.
- Step 3: Three years in advance of the first monthly compliance period, LSEs are advised of their pro rata share of the system and local RARs based on their then-current load serving obligations – i.e., based on their then-current peak load ratio shares.
- Step 4: At predetermined times in advance of the compliance period, the CAISO conducts voluntary participation auctions in which entities that own qualified capacity resources may offer to sell and LSEs may offer to buy capacity. Offers to sell are cleared against offers to buy. Constellation would suggest that these voluntary auctions should be conducted once a year for the first two years before the compliance period. An additional voluntary auction would be held shortly before each monthly compliance period.
- Step 5: One month prior to the compliance period, LSEs are advised of their share of the RAR based on their then-current peak load ratio share. This allocation represents their RAR procurement obligation, and would address changes that occurred due to load migration.
- Step 6: One month prior to the compliance period, all LSEs submit their bilateral capacity purchases to the CAISO. Any qualified capacity resources that are not already committed through a bilateral agreement may offer their capacity directly to the CAISO for clearing in the market. The sum of the bilateral capacity plus the additional resources provided to the CAISO is then calculated, and the clearing price of the demand curve auction is the point on the demand curve that corresponds to this aggregate amount of capacity that has been offered into the market. A separate demand

curve auction is conducted for each defined load pocket reflecting the load and resources in those constrained areas.

- Step 7: All LSEs pay the demand curve clearing price for the compliance month. To the extent an LSE offered its bilaterally contracted capacity into the demand curve auction, it receives the demand curve clearing price for that capacity, so that the cost to an LSE who purchased bilateral capacity to meet its obligation is the price embedded in that bilateral agreement.
- Step 8: To the extent that capacity is committed through the demand curve auction that exceeds the established RAR, which can occur because all Qualified Capacity may participate, the excess is paid for by all LSEs at the demand curve clearing price on a load ratio share basis.

Constellation's Cal CIM proposal did not initially make explicit provision for backstop procurement. In its update proposal, Constellation reiterates its concern that inclusion of a backstop mechanism in the RA program creates a risk of the backstop mechanism becoming the primary investment vehicle for new generation. To avoid such an outcome, Constellation proposes that the backstop mechanism should have specific and clearly defined trigger criteria, that any trigger of the backstop procurement mechanism should, in turn, trigger a comprehensive review of why the market did not produce price signals to support investment, that backstop procurement should be for capacity only, that capacity committed through backstop procurement be subject to the same resource obligations as resources committed directly by LSEs, and that the backstop contract be of short duration such as two to three years.

3.5.2.5. Mirant's Proposal

Mirant's proposal is in several respects similar to the Constellation Cal CIM proposal. Mirant proposes to build off the work that has been done in establishing the RA program, retain various program elements (including the criteria for determining how resources are counted, local capacity requirements, and policies for enforcing the requirements), and focus on what critical elements are missing. Mirant proposes to change the RA obligation from the current monthly peak demand to annual peak demand, extend the NQC counting rules to imports and demand response resources, and establish an "unforced capacity product."

Finding the critical missing element of the current program to be a market clearing price for capacity resources, Mirant proposes the establishment of a centralized capacity market with a locational aspect, a downward sloping demand curve that incorporates a CONE estimate, and a PER deduction. Noting that the PJM and ISO-NE provide multi-year forward components, and that those markets are yet "untested," Mirant does not propose requiring a multi-year forward commitment at this time.

3.5.2.6. PG&E's Composite Proposal

PG&E's Composite Approach would combine the use of long-term contracts with a centralized market. PG&E believes that the RA program should provide incentives for the development of the right mix of resources (providing a range of "Critical Attributes" such as environmental performance, use of sustainable fuels, location, and ability to provide services such as voltage support) as well as capacity availability to the CAISO. PG&E believes that bilateral contracting is particularly well-suited for the former purpose while centralized markets work best for uniform products such as megawatts of available generation. The Composite Approach blends the bilateral and centralized market methodologies. PG&E describes the five basic steps of this approach as follows:

1) **Identifying Needs Through the Comprehensive Forward Assessment (CFA)**. As with every proposal, the process should begin with the identification of future needs, including the full

range of the Critical Attributes necessary to attain the Commission's vision for California's energy infrastructure.

2) **Opportunities for Self-Supply**. Market participants, including LSEs, would have the opportunity to propose infrastructure projects to satisfy the needs identified in the CFA, as well as to provide the CAISO with access to resources prior to the operating year, outside of the centralized procurement mechanisms.

3) **Targeted Infrastructure Procurement Through Centralized Requests for Offers (CRFO)**. Residual procurement of infrastructure projects needed to provide California with an infrastructure possessing the Critical Attributes, as identified in the CFA, would follow the self-supply period. CRFOs would be run for each of the three Transmission Access Charge (TAC) areas in the CAISO control area.[23]

4) **Centralized Market Procurement of a Uniform Availability Product**. A Centralized Availability Market[24] would operate a year ahead of the operating year to procure residual availability needs, providing the CAISO access to the megawatts it needs committed at the right times and locations.

5) **Cost Allocation on Proportional Load-Share Contemporary with Costs**. Costs of the Centralized Availability Market and the CRFOs would be allocated to LSEs in the CAISO control area as costs are incurred, based on the portion of each LSE's load share in each TAC area in which it serves load not covered through self-supply.

PG&E explains that the CFA, which would be finalized with Commission approval approximately five and one-half years ahead of the compliance period, would guide forward procurement by LSEs, signal to resources the likelihood of their being needed, and serve to control procurement through the CRFO process. A separate CRFO process would be conducted for each TAC area by the

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[23] TAC Areas are essentially analogous to IOU service territories.

[24] PG&E uses the acronym "CAM" to refer to the Centralized Availability Market. Since this decision uses "CAM" to refer to the Cost Allocation Mechanism adopted in D.07-06-029, we do not adopt PG&E's use of it here.

corresponding IOU acting as a CAISO agent, or, if the IOU declines, by a special purpose entity. Resources procured in the CRFO would be required to bid in the Centralized Availability Market as price takers. The Centralized Availability Market, operating under the CAISO tariff, would procure the availability of resources for commitment by the CAISO. CRFO and Centralized Availability Market costs would be assessed to LSEs on the basis of their proportional load share in the TAC area and billed through the CAISO's settlement system.

3.5.2.7. Staff Recommendation 1

Staff entitles its proposal the Modified Centralized Market (MCM). Staff finds significant potential benefits with a centralized market approach, particularly with respect to price transparency and equitable cost allocation. At the same time, staff raises concerns about the interaction between a centralized capacity market and California's hybrid market approach as well as the impacts of a centralized market on environmental policies such as GHG reduction and promotion of renewable generation. To address these concerns, staff's MCM proposal combines elements of CFCMA's CFCM proposal and PG&E's Composite Proposal. The basic concept is to provide price signals for new generation via a centralized clearing mechanism while retaining Commission jurisdiction over procurement related to environmental and other policy goals.

The MCM has two distinct mechanisms: the Preliminary Capacity Showing (PCS) and the Centralized Forward Reliability Mechanism (CFRM). The PCS is a forward capacity showing required of IOUs only. Six years before the delivery year, the Commission, in conjunction with the CEC, would establish the projected load for each IOU for the delivery year. IOUs would be required to make a showing that they have procured capacity to meet 90% of their projected load six months before the CFRM is run. The remaining 25% of the IOU's procurement obligation would be met through the CFRM.[25] IOUs would be required to be exposed to the CFRM price for at least 5% of the forecast load plus the PRM.

Staff describes the CFRM as a call option on energy that takes place via procurement of a capacity product bundled with a PER deduction. It would be operated under CAISO authority and subject to the FERC-approved tariff. All LSEs participating in the CAISO would be required to purchase capacity through the CFRM, but provision for a forward showing equivalent to the PCS for IOUs would enable all other LSEs to limit their exposure to the CFRM pricing. There would be four separate auctions beginning four years before the delivery year. Trading of previously contracted capacity would be allowed in subsequent auctions, and suppliers would be allowed to buy out of their supply obligations. Ex post PER deductions would apply to all capacity that participates in the CFRM. While there would be no floor price, staff recommends a bid cap of 1.5 times CONE. All capacity would be required to participate in the CFRM via a list/delist option where generators set a clearing price below which they will not participate further. The purpose of the list/delist obligation is to allow suppliers the freedom to enter and exit the market while allowing for close monitoring by the CAISO of the impact of delisting on grid reliability.

3.6. Preferred Policy for Resource Adequacy

3.6.1. Metrics for Evaluation of Options

The Staff Report identified and recommended the following metrics for weighing and screening the options for the RA program:

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[25] Including the 15% PRM, the IOU's total procurement obligation would be 115% of its projected load. The IOU's obligation to participate in the CFRM for 25% of its projected load is based on the difference between 115% and 90%.

- **Ensures Reliability**. Staff associates short-term reliability with this metric and long-term reliability to the following metric. Staff believes the primary considerations for short-term reliability are whether there is sufficient capacity under contract to meet expected needs and whether there is an adequate backstop mechanism if the primary markets fail to provide sufficient resources.
- **Enables New Generation**. Staff notes that facilitating new generation in California is complicated by statutory provisions in Sections 454.5 and 454.6 that provide for utility-owned generation, the RPS program, the need for new generation to replace older, inefficient plants, and the need for new generation in specific locations. Staff also notes that to the extent that energy market prices are capped or energy market revenues are unreliable, capacity payments are needed to ensure generators recover the full costs of their investments. This is an especially important consideration for resources that are only used for peak hours.
- **Adheres to Least Cost Principles**. Staff notes that the costs to be minimized include energy, capacity, ancillary services, transmission services, and market administration costs. In addition, staff notes that competition drives down costs and it is therefore important to ensure transparency in pricing and full participation in markets by buyers and sellers.
- **Enables Direct Access**. Staff notes that retail competition is part of the overall policy framework for electric regulation, and that the impacts of any RA program on direct access providers must be considered.
- **Recognizes Jurisdictional Constraints**. Staff believes that the amount of control that can be exercised to protect ratepayers in case of market failure is of significant concern. Since the CAISO is FERC-regulated, this Commission's ability to exert direct control or intervene to remedy perceived dislocations and unreasonable results in a CAISO activity is limited. At the same time, staff points out that Commission jurisdiction does not extend to all California market participants, and it is important to recognize that the

Commission-jurisdictional market will not be fully comprehensive in addressing the State's reliability needs.[26]

- **Facilitates Environmental Policies**. Staff believes that the RA program options should be evaluated with regard to their impact on the state's environmental policies, including but not limited to the issues of greenhouse gases and renewables, and *vice versa*.
- **Possesses Fundamental Feasibility**. Staff recognizes a need for the program to operate with both internal and external structural compatibility. As staff sees it, topics related to feasibility include program expense, administrative burden, internal structural consistency, and compatibility with California's market.

In general, parties commented favorably on staff's proposed evaluation metrics but with some reservations. CFCMA, Mirant, and PG&E take the position that the metrics should not be assigned the same weight, a proposition with which we concur. For example, in the context of the RA program, we believe that ensuring reliability and adhering to least cost principles are more important than enabling direct access.

IEP would add the metric of consistency with the law, particularly AB 57's requirement that IOUs develop procurement plans that include competitive procurement and Section 380's requirement for uniform RA requirements for all LSEs. PG&E makes similar points regarding consistency with Section 380. Again, we concur. As we stated earlier, Section 380 is the foundation for the RA program, and consistency with the statute is clearly a key metric for evaluating any of the options for the program.

BTG would expand upon and restate "enables new generation" to confirm that this metric encompasses the need for new generation in particular local areas

[26] The Commission has noted that the service territories of the three largest IOUs in California account for 80% of California's electricity usage. (D.04-01-050, Finding of Fact 4.)

and of a particular type. BTG notes that Section 380(c) imposes a locational requirement for resource adequacy and that Section 454.5(b)(11) requires IOU procurement plans be designed to increase "diversity of ownership and diversity of fuel supply on nonutility electrical generation." BTG further notes that the RPS means that renewable generation is preferred over new fossil fuel generation. Thus, BTG asserts that RA proposals should be evaluated not only on whether they enable new generation *per se*, but also whether they enable the types of generation that fits California's unique reliability needs. We concur with BTG that this is a key consideration in evaluating the options before us. If the RA program succeeds in bringing about new generation that provides generic capacity needed for reliability, perhaps even local reliability, but fails to account for the need for renewable generation, there could be a need for additional, duplicate investment in renewable generation in California. The reliability objective could be met even while the least cost and policy coordination objectives are jeopardized. Other things equal, an option that better accommodates California's need for specific types of generation should be preferred over other options.

Aglet takes issue with the metric of enabling direct access because the role of direct access is being evaluated in R.07-05-025. As Aglet puts it, "[n]o capacity market proposal should be required to conform with a goal that the Commission has not yet established." (Aglet Comments at 2.) CUE questions the need for this metric, and in effect argues that other metrics are more important. AReM on the other hand fully supports this metric, arguing that whatever market approach is adopted—bilateral or centralized—the Commission should thoroughly evaluate the potential adverse consequences particular to ESPs and retail market competition. We stand by our earlier determination (See Section 3.2

of this decision) that, as part of our policy and program coordination objective for the RA program, any program redesign should, to the extent possible, support or avoid undermining the broad objective of a competitive retail market. Since the reopening of direct access is currently being explored in other venues,[27] it would make no sense to redesign the RA program without any regard to its potential impacts on ESPs and retail competition. As noted earlier, however, certain other metrics, particularly reliability and least cost, should be given greater weight.

We find that staff's recommended analysis metrics closely track the objectives for the RA program that we identified earlier, and represent a useful analytical tool for screening the options before us. Accordingly, we accept their use subject to the qualifications discussed above.

3.6.2. Balancing the Program Objectives

Each of the options before us, including the status quo, has a particular set of strengths and weaknesses, and no one option simultaneously improves upon achievement of each of the RA program objectives with unqualified success. The task at hand is to determine which option comes closest to optimal achievement of the objectives and is most consistent with the metrics discussed earlier.

3.6.2.1. Bilateral Versus Centralized Options

A key determination in evaluating the options is whether a bilateral option or one that employs a CAISO capacity auction should be adopted. We first note that implementation of a bilateral option would have certain short-term

[27] R.07-05-025 is our current rulemaking regarding whether, or subject to what conditions, to lift the suspension of direct access. Senate Bill 695 (Stats. 2009, Ch. 337), among other things, partially lifts the existing suspension of direct access and requires the Commission to authorize direct access transactions on a phased-in basis subject to a kilowatt-hour cap.

administrative advantages since it would build off the current program. In contrast, establishing a centralized auction involves more fundamental changes in the program and redefinition of the roles of the Commission, the CEC, the CAISO, and the FERC. For example, in addition to designing the actual auction process, it would be necessary in the case of the CFCMA proposal, and may be necessary or desirable in the case of other proposals, to develop an estimate of CONE and procedures to keep it current over time. However, with its development of the MRTU, the CAISO has had considerable experience developing a market mechanism with stakeholder input and FERC oversight. This experience would be invaluable to the CAISO in establishing a central capacity auction. In addition, the established capacity mechanisms in the eastern United States may provide important lessons for developing an auction mechanism in California. Overall, we do not see ease and cost of initial implementation to be factors of overriding significance that would lead us to favor one approach over the other.

Of far greater significance is the scope of Commission jurisdiction concerning the RA program. Less than a decade ago, California experienced the results of a costly, disastrous experiment with the redesign of electricity markets when painstakingly designed mechanisms did not function as intended by the Commission. As the 2000-2001 energy crisis played out, California found that its ability to craft its own remedies was limited because much of the electricity market regulatory apparatus had been federalized.[28]

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[28] We recognize that this was not necessarily unanticipated. Years earlier, in its landmark electricity restructuring decision, the Commission understood that it was effectively transferring a portion of its authority to regulate vertically integrated utilities to the FERC. For example, as to the unbundling of transmission the Commission stated that ". . . it is clear that under the new market structure proposed today, the FERC will

While we do not shy away from considering potential new market mechanisms solely on the basis of that experience, we should take full advantage of the lessons learned from it. Specifically, it must be recognized that maintaining our current scope of jurisdiction over the RA program is a very important benefit of the bilateral approach in terms of achieving the RA program objectives. It would enable the Commission to make changes to the program going forward, both for routine program refinement and for responding to any market breakdown or other unforeseen consequences.

The bilateral approach rests on our jurisdiction over LSE procurement and therefore maintains our jurisdiction over much of California's RA program. As noted earlier, options that involve a centralized auction operated by the CAISO would place a significant portion of the RA program under the jurisdiction of FERC. The Commission would not have direct authority to refine the program or remedy problems should they arise in the context of a CAISO-centered auction mechanism. As the BTG explains in analyzing the experience of states in the ISO-NE jurisdiction and in New York, the FERC's assertion of jurisdiction

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be regulating a significantly larger portion of transmission revenues than it currently does." (*Re Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation*, 64 CPUC2d 1, 36.) As to establishing a power exchange market mechanism, the Commission noted that:

> The establishment of the Power Exchange will require close coordination between the FERC and this Commission. The Power Exchange will have the function of bringing buyers and sellers together. Although the Power Exchange itself will not "sell" power, it will establish market prices for sales for resale. [¶]The Federal Power Act (FPA) confers exclusive jurisdiction over rates, term, and conditions for sales for resale (wholesale sales) on the FERC. Retail sales, even if the power originates out-of-state, are subject to exclusive state jurisdiction. [¶]Because the power bid into the Power Exchange may be sold for resale, pricing mechanisms, including bidding protocols, will be subject to FERS's oversight. (*Id*. at 41.)

over resource adequacy in the context of centralized capacity markets is very broad, and states and utilities in those markets find themselves subject to resource adequacy capacity requirements and associated costs set by FERC.[29] Recently, the D.C. Circuit Court of Appeals affirmed FERC's jurisdiction to review ICRs in the New England bulk power system, holding that "[w]here capacity decisions about an interconnected bulk power system affect FERC-jurisdictional transmission rates for that system without directly implicating generation facilities, they come within the Commission's authority." (*Connecticut Department of Public Utility Control v. FERC*, No. 07-1375 (D.C. Cir. June 23, 2009), slip. op. at 15.)

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[29] BTG cites to FERC's assertion that the basis for its resource adequacy jurisdiction is that the ISO-NE's Installed Capacity Requirements (ICRs) affect wholesale rates of electricity, over which FERC has jurisdiction pursuant to Section 205(a) of the Federal Power Act (FPA). (*ISO New England, Inc.*, No. ER05-7125-002, 122 FERC P61, 144 (Feb. 21, 2008).) BTG also notes that in an order issued the same day, the FERC denied a request for rehearing by the New York Public Service Commission (NYPSC) challenging FERC's jurisdiction to impose ICRs for the New York Control Area. (*New York State Reliability Council*, No. ER07-429-1, 122 FERC P61, 153 (Feb. 21, 2008).) The NYPSC had relied on Section 215 of the FPA, added by the Energy Policy Act of 2005, which expressly provides that in facilitating the creation of electricity reliability organizations subject to FERC's oversight, it does not preempt state authority over adequacy and reliability of electric service. However, in the *New York* order, the FERC claims that it

> did not "usurp," "intrude on," or "preempt" any authority exclusively within the jurisdiction of the New York Commission. Section 215(i)(2) of the FPA does not reserve authority over all matters related to or that flow from "resource adequacy," as the New York Commission suggests. The reservations of authority found in Section 215(i)(2) apply to the exercise of Commission jurisdiction under that section, not under other provisions of the FPA. The Commission has an independent obligation under sections 201, 205, and 207 of the FPA to consider whether practices affecting jurisdictional transactions result in rates, terms and or conditions that are unjust, unreasonable, or unduly discriminatory. That is what the Commission has done in this proceeding. . . . (*Id.*, para. 33.)

Another important consideration, related to the jurisdictional issue, is the interaction of the RA program with California's decision to invest heavily in the development and use of renewable resources and resources that meet GHG reduction goals. As we determined in reviewing Energy Division's proposed evaluation metrics, we prefer RA program options that enable new generation of a particular type, and those that facilitate environmental policies. We are concerned that the underlying premise of a centralized auction is to promote investment in, and development of, generic RA capacity. A policy of having a large pool of generators bidding against each other for a standard product may provide insufficient regard to the environmental and operational aspects of the resource. Indeed, a centralized auction may not be successful unless a large proportion of the product being bought and sold is fungible.

While a centralized auction approach may be well-suited to achieving system reliability, it is less clear that this is true for satisfying local reliability across multiple local capacity areas. Moreover, it is not necessarily the most effective for enabling the development and trading of specialized capacity that meets environmental goals of the State of California and the operational needs of the CAISO. To the extent that the RA program results in development of new capacity but fails to bring about investment in specialized resources that will need to be developed in any event, irrespective of RA needs, the result could be unnecessary and costly duplication of capacity investment. Notwithstanding California's environmental goals that disfavor coal-based electric generation, a centralized auction operated by the CAISO could result in ratepayer-supported capacity payments to new conventional coal plant development. Achievement of the least cost objective of the RA program would clearly be jeopardized in such a scenario.

We find that a bilateral trading regime is more conducive to the development of specialized resources that meet California's environmental objectives, and the avoidance of development of excess capacity, than a centralized auction would be. In light of our objective to ensure coordination with policy initiatives that could be impacted by the RA program, as well as our objective to ensure reliability at least cost, this is a significant consideration in weighing the options for the RA program.

On other hand, the centralized mechanisms proposed by CFCMA and CAISO have certain distinct advantages over the bilateral capacity trading approach. They would solve some of the more difficult issues associated with the bilateral approach, whether in its current form or in a form that includes a multi-year forward commitment. The bilateral options assign procurement obligations to individual LSEs on the basis of LSE-specific load forecasts. In light of forecast uncertainty and load migration that takes place after procurement obligations are assigned to LSEs, it is desirable to institute compensating procedures, such as the current program's provision for monthly true-ups of "system" procurement obligations to ensure that all LSEs pay their fair share of capacity costs but are not unduly saddled with costs incurred on behalf of customers they no longer have. Such procedures have proven challenging to design and implement.[30] Moreover, dealing with these issues could be exacerbated with the potential entry of new firms serving the retail market.

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[30] For example, a recent decision on the RA program revisited the recurring issue of whether to use the "best estimate" or "current customer " method of calculating LSE-specific load forecasts. (D.09-06-028 at 30-34.) It also revisited the open question of whether to allow for true-ups for load migration in connection with the local component of the RA program. (*Id*. at 34-41.) These issues have not been fully resolved.

Under the central auction approach, there is no need for administratively determined LSE-specific load forecasts. Rather than being required to make forward commitments, LSEs would pay for capacity at or near the time of delivery based on their actual proportionate load shares.[31] This approach would resolve the related issues of LSE-specific load forecasting methodology and load migration. It would also address the problem of adequate creditworthiness for some LSEs having to make forward commitments.

In addition, the central auction mechanisms would provide a more transparent market than the bilateral trading approach, even if an electronic bulletin board mechanism is included in the latter. In theory, a more transparent market should lead to greater economic efficiency, which in turn should translate into greater achievement of the least-cost objective for the RA program. Also, with a centralized auction approach, market power would be more transparent and thus more amenable to mitigation.

Finally, depending on how it is structured, a comprehensive centralized auction approach could supplant, at least in significant part, the need for any other backstop procurement mechanism. For example, the reconfiguration auctions in the CAISO's proposal would provide a natural backstop function.

Although the centralized auction approach has several potential advantages as just described, we find that a bilateral trading approach will better meet our objectives for the RA program as well as the metrics we have approved for reviewing the program options. We make this determination in light of the overriding importance that we ascribe to maintaining our current scope of jurisdiction over the RA program by keeping the program's focus on LSE-based

[31] Most centralized auction mechanisms would allow or encourage LSEs to forward contract to hedge against price uncertainty in the auction.

procurement obligations, as well as our determination that bilateral trading is more conducive to development of the types of capacity resources that are consistent with our policies for the electric sector.

Even if we were inclined to approve a centralized auction mechanism for California, we find reason not to approve a centralized auction approach at this time. The same general approach has been in place in the eastern United States markets for a few years, but we do not find that it is yet a proven, long-term success story. The experience in PJM may be instructive. On May 30, 2008, a coalition of state regulatory commissions, municipal electric utilities, joint power agencies, a rural electric cooperative, end-use customers, state consumer advocate offices, and LSEs participating in the PJM central capacity market known as the Reliability Pricing Model (RPM) filed a complaint with the FERC[32] (RPM Buyers Complaint). Focusing on a series of alleged flaws in the RPM market design, including short lead times for transitional auctions, extreme sensitivity to small changes in demand and supply curves, vulnerability to market power exercise combined with lack of adequate market power mitigation, and excessive reliability requirements imposed by PJM in local areas, the RPM Buyers Complaint alleged that the RPM has led to excessive, unjust, and unreasonable capacity prices. The complaint sought a refund for PJM customers of $12 billion.

On September 19, 2008, the FERC dismissed the RPM Buyers Complaint,[33] and on June 18, 2009, it denied both a request for rehearing of the earlier

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[32] *Maryland Public Service Commission, et al. v. PJM Interconnection, L.L.C.,* FERC Docket No. EL08-67-000.

[33] *Maryland Public Service Commission, et al. v. PJM Interconnection, L.L.C.,* 124 FERC ¶61,276 (2008).

dismissal order and a request for oral argument.[34] The FERC found that no party had violated PJM's tariffs, and that even though the RPM tariff provisions are continually subject to revision on a prospective basis, and RPM revisions may be appropriate in the future,[35] the RPM Buyers had failed to support their contention that these provisions were unjust and unreasonable so as to warrant the undoing of already conducted auctions. The FERC noted that all offers in the contested auctions were subject to mitigation according to the PJM tariff and that the PJM Market Monitor found no significant exercise of market power occurred.

There undoubtedly are limits to the applicability of the experience of capacity market mechanisms in eastern markets to California-specific circumstances. Still, we can draw certain lessons from the RPM Buyers Complaint and FERC's disposition of it. First, as in the PJM, development of a capacity auction mechanism in California most likely would be accompanied by difficult challenges involving a complex balancing of several market design elements. It would almost certainly be an ongoing and potentially disruptive process, even after initial implementation. As the FERC's orders suggest, the RPM remained subject to further revision, and was essentially a work-in-progress, as it was implemented. Second, because a decision to move to a centralized auction in California would not be an easily reversible choice, there would be a clear benefit to observing the PJM experience (as well as that of the ISO-NE and NYISO markets) play out further before determining whether a centralized auction operated by the CAISO is the best solution for California.

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[34] *Maryland Public Service Commission, et al. v. PJM Interconnection, L.L.C.*, 127 FERC ¶61,274 (2009).

[35] On March 26, 2009, in *PJM Interconnection, L.L.C.*, 126 FERC ¶61,275 (2009), the FERC approved revisions to the RPM program.

Finally, we consider the advice of the CAISO's Market Surveillance Committee (MSC) to refrain from making a major policy shift to a centralized auction at this time.[36] Noting uncertainty with respect to the MRTU,[37] the future of retail choice in California, and California's aggressive renewable energy and GHG emissions goals, the MSC stated that:

> Although we have a number of concerns with the performance of California's electricity market, we do not believe that any of the current capacity market proposals effectively address them. In fact, given the wide range of uncertainty surrounding the future organization and structure of California's electricity market, as well as the performance of new capacity-market structures in eastern markets, it appears to us to be a singularly inappropriate time for California to commit to a new resource adequacy mechanism with potentially significant cost consequences. In short, we believe there is substantial value to deferring any major overhauls of the Resource Adequacy structure until California's specific needs for such a [long term] RA product are known with greater clarity.[38] (Staff Report, Appendix 4 at 115.)

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[36] The MSC was established by the CAISO to provide independent, external expertise on the CAISO's market monitoring process and independent expert advice and recommendations to the CAISO Chief Executive Officer and Governing Board. On October 1, 2007, the MSC met to discuss the proposals before the Commission and the capacity market proposals that the CAISO reviewed in its stakeholder process. On November 5, 2007, the MSC issued an independent report (*Final Opinion on Resource Adequacy Under MRTU,* issued by Frank A. Wolak, Chairman, James Bushnell, Member, and Benjamin Hobbs, Member), referred to herein as MSC Report. The MSC Report, included with the Staff Report as Appendix 4, did not represent the opinion or position of the CAISO, and in fact the CAISO included a response to the MSC Report in its opening comments on the Staff Report.

[37] The MSC Report was issued before the initial, first-phase implementation of the MRTU. However, the report noted that "important changes will follow in years to come." (Staff Report, Appendix 4 at 116.)

[38] We understand that the MSC's views on deferring a major overhaul of the RA structure may encompass the addition of a multi-year forward commitment to the current bilateral regime. If that is the case, we would disagree with the MSC on this point for the reasons discussed extensively in this decision.

With respect to retail choice and direct access, and the state's environmental policies, the MSC stated the following:

> A major uncertainty concerns retail choice, which is currently unavailable to most electricity consumers in California. This may change soon with the potential rise of community choice aggregation, as well as an ongoing proceeding at the [Commission] to consider a return of [direct access]. It is important to recognize that the existence and form of retail choice is an essential piece of information necessary to craft a satisfactory resource adequacy policy. Without retail choice, much of the rationale for FERC-based [long-term] RA policies goes away because the vast majority of load will continue to be served by [Commission]-jurisdictional entities. Even if it is reinstated, the conditions of retail choice, such as the extent of eligibility, costs of 'exit' and 'conditions for return' are important factors in determining the need for and preferred attributes of an RA policy. None of these features are known with any kind of certainty today. (*Id*. at 116.)
>
> Finally, California's significant energy efficiency and renewable energy goals imply that there is little need for additional energy from non-renewable generation to meet future load growth through 2020. Meanwhile, uncertainties concerning the design and costs of California's GHG emission control policies further complicate the RA paradigm. While there will likely be a need for some fossil fuel generation unit investments to operate the [CAISO] control area with a significantly larger renewable energy share, we do not believe that the current capacity-market proposals would fill these focused needs. (*Id*.)

The MSC then concluded that:

> Thus, in general, the long-run economic organization of the California market remains very much a moving target. Given the great degree of uncertainty and ongoing change currently at play in California, we feel that a far more prudent and cost-effective course of action at this point is to refine the current RA paradigm to correct known flaws rather than completely overhaul it, while preserving the option of a full redesign at a later date. Moreover, a number of potential problems with the current RA paradigm may be addressed by MRTU. As the MRTU implementation process identifies the

> need for new energy and ancillary service products, new RA needs may be identified. A number of the eastern ISOs are currently in the initial stages of implementing new long-term capacity payment mechanisms in response to perceived shortcomings in their former capacity payment mechanisms. Another market, Texas, is pursuing the so-called 'energy only' path. By delaying significant changes in its RA paradigm, California can learn from the experience of these ISOs. (*Id.*, 116-117.)

3.6.2.2. The Preferred Option

Having determined that continuing the current, LSE-based, bilateral RA structure best meets our objectives for the RA program, we now evaluate the options that follow this approach. As noted earlier, there are three bilateral procurement options before us that continue the year-ahead forward procurement obligation: (1) maintaining the current RA program, which includes evolutionary change through periodic review proceedings; (2) the BTG proposal, which maintains the current framework but, among other things, makes explicit provision for an electronic bulletin board; and (3) Staff Recommendation 2, which is similar to the BTG proposal but includes a commitment to consider a multi-year forward procurement obligation in a future proceeding. The two bilateral trading options that include provision for a long-term forward commitment are PG&E's proposed multi-year bilateral approach and Aglet's recommendation for adding its proposed PCOM (as well as a multi-year forward commitment) to the current bilateral approach.

We find that the heart of Aglet's proposal, the PCOM itself, was not sufficiently developed and vetted during workshops or in comments to warrant further consideration at this time. We have several concerns and questions about the PCOM that are not adequately addressed or resolved in the record, including: (1) whether there are any similar market approaches in place that would provide enlightenment on how this approach might function in

California, (2) the feasibility of the Commission staff overseeing a market mechanism, and (3) whether the PCOM would be subject to FERC jurisdiction and thereby raise the same types of concerns that we have with the centralized capacity auction proposals.

PG&E's bilateral proposal has several potentially beneficial aspects. It meets the metrics of ensuring reliability, enabling new generation, and facilitating environmental policies. By maintaining its focus on LSE-based procurement obligations, the RA program would remain within the Commission's jurisdiction. The metric of "fundamental feasibility" is clearly met since the option maintains the bilateral approach that is now in operation and expands on it. By preserving the Commission's jurisdiction and authority to make changes to the program in response to evolving market conditions, and by encouraging the development of the specialized types of resources that are most appropriate for California's needs, this option may contribute substantially to lowering generation costs that are ultimately paid by ratepayers. Additionally, this option meets the metric of consistency with the law, particularly Section 380. However, the one metric of overriding concern for this option is that it fails to enable or support direct access. In fact, as the record makes clear and the comments on the ALJ's proposed decision reiterate, requiring a multi-year forward commitment would be more difficult for ESPs than IOUs to comply with because ESPs lack ratepayer-guaranteed funding and may be less creditworthy than IOUs, and because load forecast and load migration issues associated with the current program could be accentuated with a forward commitment greater than one year.

We determine that neither of the bilateral procurement options that includes a multi-year forward obligation adequately conforms to our stated metrics for resource adequacy, and therefore determine that the RA program should be continued in effect with a year-ahead procurement framework. Of the three variations of this approach described earlier, we find that the recommendations advanced by the BTG best meet our objectives and evaluation metrics. Most importantly, the BTG approach recognizes the need for improvements to the bilateral trading platform, including the need for a bulletin board type mechanism, as well as the need to address modifications to the backstop procurement mechanism and the cost allocation mechanism adopted in D.06-07-029, all while retaining the current program's essential character. In contrast, Staff Recommendation 2 would require a commitment to consider the implementation of a multi-year forward commitment, which approach we are rejecting at this time.

In conjunction with the BTG approach, we adopt in principle one feature of Staff Recommendation 2—its provision for development of a collaborative forward assessment of capacity need with a multi-year horizon. Even though we are not prepared to impose a multi-year procurement obligation on LSEs through the RA program, we see the forward assessment as an indispensible tool that would assist all market participants by providing high-quality official supply and demand information.

3.7. Implementing the Preferred Option

We find that we should not make explicit provision at this time for initiation of a dedicated implementation proceeding, although we fully recognize that further Commission action may be called for in appropriate proceedings. We make this determination in large part due to the passage of time since the record of this proceeding was closed along with our expectation that ongoing developments may have impacted the nature of proceedings that will be required. For example, the BTG proposal addresses the need for a tradable capacity product, yet we are aware that progress has been made on this topic.[39] Similarly, we are informed that recent developments may have impacted the need for, or nature of, further proceedings regarding development of an electronic bulletin board.

We are committed to the implementation of the policies adopted today, including such elements of the BTG proposal as the electronic bulletin board, a tradable capacity product, and a durable backstop mechanism that builds off (and modifies as appropriate) the Cost Allocation Mechanism adopted in D.06-07-029. Rather than rely upon the current record as the basis for ordering a new proceeding, we ask our Energy Division to evaluate today's policy decision in light of current regulatory and market developments, and to make recommendations as necessary and appropriate to ensure that the adopted policies are carried out. Such recommendations may include the initiation of new proceedings or the inclusion of particular topics in existing proceedings.

We are also interested in receiving Energy Division's recommendations for developing the collaborative forward assessment process envisioned by Staff Recommendation 2. California's energy agencies and the CAISO already perform some of the necessary functions, but it will be necessary to put a process in place that meets the needs of the RA program while avoiding duplication of other processes being undertaken by the Commission, the CEC, and the CASIO. It may be most effective to continue to rely on the experience of the CEC and the CAISO for specific elements of the analysis, as both entities conduct analyses covering this extended time horizon. We also note the possibility that the

[39] See, for example, D.09-06-028 at 42-44.

collaborative forward assessment may overlap the needs assessment process of the LTPP program in important respects. We welcome Energy Division's recommendations on whether, and if so to what extent, to coordinate or even to merge these processes.

At this time we refrain from specifying either the precise scope of the analysis or the respective roles of these entities, or the roles of the IOUs for that matter, in performing the collaborative forward assessment. Still, we recognize that any of a wide range of roles for this Commission will require resource augmentation for our Energy Division. A collaborative forward assessment will require a more complex analysis of supply resources and demand-side resources, particularly new resources not yet in place, than has previously been performed for the RA program. The assessment will also need to include renewable integration issues not previously addressed in the RA process. Accordingly, we will authorize our Executive Director to commit to expenditures not to exceed $1 million per year for consultants to assist the Energy Division in performing the analysis necessary to develop the record of the implementation proceeding on the appropriate collaborative forward assessment. We intend that reimbursement for any such expenditures would be paid by some or all LSEs through mechanisms to be developed in future proceedings.

4. Cost Allocation Mechanism Opt-Out

4.1. Background

Decision 06-07-029, as modified by D.07-11-051, designated the IOUs as the procuring agents to sign long-term power purchase agreements (PPAs) for new resources, and it adopted a cost allocation mechanism (CAM) that provides for the advantages and costs of those resources to be shared by all benefiting customers in the IOU's service territory. Capacity and energy from the PPAs are unbundled, and rights to the capacity are allocated among all the LSEs in the IOU's service territory according to each LSE's share of the coincident peak. LSEs can apply this allocated CAM-related capacity towards their RA procurement obligations.

In D.06-07-029, the Commission found appealing the concept of an opt-out mechanism, stating that it would like to agree with parties who say that "any LSE that can demonstrate that it is fully resourced with new generation for the 10-year time frame may opt-out of the cost allocation mechanism." (D.06-07-029 at 35.) However, the Commission expressed concern that there was no viable enforcement program or mechanism for doing so. D.06-07-029 therefore deferred any CAM opt-out mechanism to this proceeding, where it could be considered along with capacity markets and multi-year RA requirements.

4.2. CAM Opt-Out Proposals

AReM, BTG, PG&E, and SCE offered CAM opt-out proposals in response to the Phase 2 Scoping Memo.

AReM would restrict the ability to opt out to non-IOU LSEs to mitigate what it sees as the inherent anti-competitive effects of the CAM. AReM proposes a dual approach. First, for PPAs authorized in D.06-07-029 for which the IOUs elect to use the CAM, non-IOU LSEs would be allowed to opt out of the CAM by demonstrating that they have procured comparable generation resources for the remaining term of the CAM. The LSE must separately procure megawatts up to its current pro-rata share of the project for which it is opting out. If the project for which an LSE opts out provides local RA capacity, the newly procured megawatts must likewise provide local capacity, albeit in any local reliability area designated by the CAISO. If the project for which an LSE opts out is new construction, the opting-out LSE would have to procure new construction. The

LSE would be able to opt out at any time during the term of the project. Second, for future projects, AReM proposes a more flexible approach with more options for LSEs. The LSE must demonstrate that it has procured megawatts up to its current pro-rata share of its peak load in the IOU service territory for which the Commission has approved future procurement. The procured megawatts must provide either system or local RA capacity, whichever has been identified by the Commission as needed for future procurement. If the project for which an LSE opts out is new construction, the opting-out LSE would have to procure new construction. If an LSE seeks to opt out before a project is approved for future procurement, it may do so with a contract term of at least four years. Compliance demonstrations would be made to the Commission's Energy Division pursuant to delegated authority. Opting-out LSEs would tie their requests to a specific set of customers for which they have signed multi-year contracts. If the opt-out is granted, billing and RA credits to the LSE and its customers would be modified accordingly to reflect the change. By locking in specific customers, load migration issues would be obviated.

BTG favors a CAM opt-out provision to encourage LSEs to enter into their own multi-year forward contracts for new generation. BTG proposes two requirements to qualify for the opt-out. First, the LSE must have signed a capacity contract of at least three years in length for a new resource that is planned to be operational within four years. Second, the capacity contract at a minimum must equal the LSE's load ratio share of the megawatts determined to be needed.

In connection with its March 30, 2007 proposal for backstop procurement, PG&E proposes that to the extent that an LSE has responsibly planned for the future by contracting for new capacity that offsets the needs identified in the needs assessment, it should receive credit for new capacity backstop costs. PG&E believes this represents the opting out process anticipated by the Commission in D.06-07-029. In its reply comments, PG&E notes that the issue of opting out of the CAM received only limited time during the workshops and was not extensively discussed in the Staff Report. PG&E requests further proceedings on this complex issue.

SCE proposes that the Commission should only allow LSEs to opt out from the CAM in connection with proceedings leading to the issuance of a Commission decision authorizing the entity tasked with conducting specific backstop new generation procurement subject to the CAM to proceed with that procurement. Any LSE authorized to opt out of the CAM would be required to submit monthly reports on the status of its procurement efforts.

TURN found fault with AReM's opt-out proposal and offered an alternative approach. Since TURN's alternative was submitted with its reply comments and was not discussed in workshops, the Staff Report, or opening comments, we find the record insufficiently developed with respect to the proposal and do not consider it here.

4.3. Discussion

As TURN points out, there are two flaws in AReM's recommended approach. First, since only non-IOU LSEs would be permitted to opt out of the CAM, only IOUs would be expected to commit new resources on behalf of bundled services customers. Non-IOU LSEs would not be bound by such an expectation. Whether or not, as TURN maintains, this one-sided aspect would create a disincentive for IOUs to commit new resources, with the result that the CAM is a primary procurement vehicle rather than a backstop, we see no sound basis for the disparate treatment of LSEs proposed by AReM.

Second, under AReM's proposal, the opt-out could occur at any time, even after the resources procured by the CAM are on line and producing power. However, once the resource has been committed under the CAM, the reliability need that gave rise to CAM procurement in the first place has been filled. Any future opt-outs would lead to over-procurement for the system and stranded costs for which the IOUs and their customers would be responsible. We do not find this outcome to be reasonable.

We find that the issue of the opt-out did not receive adequate attention in the workshops, the Staff Report, or the comments, and that the record does not support adoption of any of the opt-out proposals before the Commission. Therefore, pending further order of the Commission the CAM procedure adopted in D.06-07-029 will remain in effect without modification by this decision. Since this topic is closely related to the BTG proposal for a new generation backstop mechanism, it may be appropriate to further consider it in a future proceeding that addresses the backstop mechanism. We note that Senate Bill 695 (Stats. 2009, Ch. 337), which among other things added Section 365.1, impacts certain aspects of the CAM. While we do not modify the CAM at this time, we anticipate addressing any necessary changes to it in the forthcoming LTPP rulemaking. In this manner we will be able to take a comprehensive look at the CAM and make any and all necessary changes.

5. Disposition of Proceeding

This proceeding was opened in December 2005, and it is appropriate to close it at this time. Because the record of Track 3 of Phase 2 of this proceeding (establishment of RA requirements for small and multi-jurisdictional LSEs) is not complete, we determine that the Track 3 issues should be deferred to and resolved in a new rulemaking proceeding or an existing proceeding as appropriate. The Track 3 record may be incorporated into such proceeding.

6. Comments on Proposed Decision

The proposed decision of the ALJ was issued on November 3, 2009 pursuant to Section 311 of the Public Utilities Code and Rule 14.2(a) of the Commission's Rules of Practice and Procedure. Comments were filed by Aglet; AReM; CAISO; Calpine; CUE; Direct Access Customer Coalition (DACC); DRA; Dynegy; IEP; Mirant; PG&E; SCE; Shell Energy North America (US), L.P. (Shell); TURN; and WPTF. Additionally, the California Large Energy Consumers Association (CLECA), California Manufacturers and Technology Association, and the Energy Users Forum (collectively, CLECA, et al.) filed joint comments; and AReM, Dynegy, CFCMA, DACC, Safeway Inc., and Sempra Generation (collectively, Joint Parties) filed joint comments.

Replies to comments were filed by CAISO, Calpine, DRA, Dynegy, PG&E, SCE, Shell, TURN, and Joint Parties, who were also joined by AES Southland, LLC, California Alliance for Choice in Energy Solutions, Oakley, Inc., and Wal-Mart Stores, Inc.

In this decision we have given significant weight to the comments that urge us to continue the year-ahead procurement framework of the resource adequacy program without requiring a multi-year forward procurement obligation. Accordingly, we have extensively revised the text of the proposed decision to incorporate our determination that a multi-year forward procurement obligation should not be mandated at this time.

7. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Mark S. Wetzell is the assigned ALJ in this proceeding.

Findings of Fact

1. The RA program has generally yielded the availability of capacity resources that the CAISO needs to reliably operate the transmission grid.

2. Addition of a required multi-year forward capacity commitment to the RA program would potentially provide reliability and other benefits, but it is premature to conclude that most of such benefits cannot be achieved under the current RA program.

3. The RA program, in combination with the LTPP and RPS programs, is meeting California's needs for infrastructure development, and no other proposal in this proceeding offers a reasonable likelihood of doing so more effectively or at lower cost to ratepayers.

4. The RA capacity market would better promote investment, and do so more cost-effectively, if greater price transparency and symmetry of information were available to market participants.

5. An electronic bulletin board or equivalent mechanism with appropriate public disclosure of price and trading information would facilitate trading and promote greater liquidity.

6. Achieving sustained reduced payments for existing generation relative to payments for new generation would be offset by the fact that owners of existing capacity will attempt to compensate for the prospect of reduced capacity payments by adjusting their bids accordingly.

7. Third-party intermediaries would seek opportunities to capture a share of any surpluses associated with price discrimination between classes of generation, which would diminish any consumer savings associated with such price discrimination.

8. Price discrimination between resource classes would be possible only to the extent that the market is opaque, which would be inconsistent with a policy of greater price transparency and symmetry of information available to market participants.

9. The absence of a durable backstop mechanism is a shortcoming of the current RA program that jeopardizes the reliability and cost-effectiveness objectives.

10. By maintaining Commission jurisdiction with respect to LSE-based procurement, the bilateral approach ensures that the Commission is authorized to ensure that environmental policies are being met.

11. With a centralized capacity auction administered by the CAISO, the Commission's primary role in ensuring resource adequacy would be establishing, or participating in the establishment of, capacity needs assessments and issuing and enforcing regulations governing LSE participation in the CAISO auction mechanism.

12. Even if the RA program succeeds in bringing about new generation that provides generic capacity needed for reliability, perhaps even local reliability, there could be a need for additional, duplicate investment in renewable generation in California if the program fails to account for the need for renewable generation.

13. Maintaining the current scope of Commission jurisdiction over the RA program would enable the Commission to make changes to the program going forward, both for routine program refinement and for responding to any market breakdown or other unforeseen consequences.

14. RA program options that involve a centralized auction administered by the CAISO would place a significant portion of the RA program under the

jurisdiction of FERC, and under those options the Commission would not have direct authority to order refinements to the program or specific remedies.

15. A centralized auction would tend to promote investment in, and development of, generic RA capacity without significant regard to the locational, environmental, and operational aspects of the resource.

16. To the extent that the RA program results in development of new capacity but fails to bring about investment in specialized resources that will need to be developed in any event, irrespective of RA needs, the result could be unnecessary and costly duplication of capacity investment.

17. Compared to a centralized auction, a bilateral trading regime is more conducive to development of specialized resources that meet California's environmental objectives, and avoidance of development of excess capacity.

18. Development of a capacity auction mechanism in California most likely would be accompanied by difficult challenges involving a complex balancing of several market design elements.

19. Once a resource has been committed under the CAM, the reliability need that gave rise to CAM procurement in the first place has been filled, and any future opt-outs would lead to over-procurement for the system and stranded costs for the IOUs and their customers.

20. The CAM mechanism, modified as necessary to comply with Section 365.1(c)(2), will ensure that the costs of any new infrastructure required to meet system and local reliability needs are allocated fairly to the customers of all LSEs.

21. The record of this proceeding does not support making any major structural modifications to the current RA program.

22. Any of a wide range of roles for this Commission in performing a comprehensive forward assessment will require resource augmentation for our Energy Division.

Conclusions of Law

1. Based on the objectives and requirements of Section 380, as well as the Commission's prior policy determinations, the RA program's four main objectives are reliability, least cost, equitable cost allocation, and coordination with state policies for the electric sector.

2. The RA program does not require any major structural modification.

3. RA program modification proposals should be evaluated not only on whether they enable new generation, but also on whether they enable the types of generation that fits California's unique reliability needs and policy considerations.

4. Any RA program redesign should, to the extent possible, support or avoid undermining the broad objective of a competitive retail market, provided, however, that reliability and least cost should be given greater weight.

5. In light of the overriding importance of maintaining the Commission's current scope of jurisdiction over the RA program, a bilateral trading approach will better meet the objectives for the RA program.

6. Pending further order of the Commission the CAM procedure adopted in D.06-07-029 should remain in effect, subject to modification to conform to the provisions of Section 365.1(c)(2) and the determinations made in this decision.

7. This proceeding should be closed.

8. The record of Track 3 of Phase 2 of this proceeding (establishment of RA requirements for small and multi-jurisdictional LSEs) may be incorporated into an appropriate proceeding.

9. The Executive Director should be authorized to commit to expenditures not to exceed $1 million per year, reimbursable through LSE payments, for consultants to assist the Energy Division in performing the analysis necessary for a collaborative forward assessment of resource adequacy requirements.

O R D E R

IT IS ORDERED that:

1. The Commission's Energy Division shall make recommendations to the Commission as necessary to implement the policies adopted by this decision, including in particular the recommendations set forth in the proposal of the Bilateral Trading Group.

2. The Cost Allocation Mechanism adopted in Decision 06-07-029 shall remain in effect, subject to modifications in future proceedings to conform to changes that may be required by Public Utilities Code Section 365.1(c)(2) and the policy determinations made in this decision.

3. The Executive Director is authorized to employ consultants to assist the Energy Division in the development of a collaborative forward assessment of resource adequacy requirements, subject to further guidance of the Commission or the assigned Commissioner in the resource adequacy implementation proceeding as to the scope of work to be performed. To this end, the Executive Director is authorized to spend up to $1 million for this purpose each fiscal year beginning July 1, 2010, and continuing until the issuance of a final decision implementing resource adequacy requirements based upon a collaborative forward assessment. Any unspent amount for a fiscal year may be carried over to subsequent fiscal years during the pendency of the resource adequacy implementation proceeding. The Commission intends that the cost for any such

expenditures will be reimbursed through payments by some or all Commission-jurisdictional load-serving entities, as defined in Public Utilities Code Section 380(j), through mechanisms to be developed in the resource adequacy implementation proceeding.

4. Rulemaking 05-12-013 is closed. As to Phase 2/Track 3 issues delineated in the December 22, 2006 *Assigned Commissioner's Ruling and Scoping Memo for Phase 2*, i.e., resource adequacy requirements for all load-serving entities, including small and multi-jurisdictional utilities and electrical cooperatives, the record of this proceeding shall be available for consideration in an appropriate rulemaking.

This order is effective today.

Dated _____________________________, at San Francisco, California.

APPENDIX A

Public Utilities Code Section 380

(a) The commission, in consultation with the Independent System Operator, shall establish resource adequacy requirements for all load-serving entities.

(b) In establishing resource adequacy requirements, the commission shall achieve all of the following objectives:

(1) Facilitate development of new generating capacity and retention of existing generating capacity that is economic and needed.

(2) Equitably allocate the cost of generating capacity and prevent shifting of costs between customer classes.

(3) Minimize enforcement requirements and costs.

(c) Each load-serving entity shall maintain physical generating capacity adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves. The generating capacity shall be deliverable to locations and at times as may be necessary to provide reliable electric service.

(d) Each load-serving entity shall, at a minimum, meet the most recent minimum planning reserve and reliability criteria approved by the Board of Trustees of the Western Systems Coordinating Council or the Western Electricity Coordinating Council.

(e) The commission shall implement and enforce the resource adequacy requirements established in accordance with this section in a nondiscriminatory manner. Each load-serving entity shall be subject to the same requirements for resource adequacy and the renewables portfolio standard program that are applicable to electrical corporations pursuant to this section, or otherwise required by law, or by order or decision of the commission. The commission shall exercise its enforcement powers to ensure compliance by all load-serving entities.

(f) The commission shall require sufficient information, including, but not limited to, anticipated load, actual load, and measures undertaken by a load-serving entity to ensure resource adequacy, to be reported to enable the commission to determine compliance with the resource adequacy requirements established by the commission.

(g) An electrical corporation's costs of meeting resource adequacy requirements, including, but not limited to, the costs associated with system reliability and local area reliability, that are determined to be reasonable by the commission, or are otherwise recoverable under a procurement plan approved by the commission pursuant to Section 454.5, shall be fully recoverable from those customers on whose behalf the costs are incurred, as determined by the commission, at the time the commitment to incur the cost is made or thereafter, on a fully nonbypassable basis, as determined by the commission. The commission shall exclude any amounts authorized to be recovered pursuant to Section 366.2 when authorizing the amount of costs to be recovered from customers of a community choice aggregator or from customers that purchase electricity through a direct transaction pursuant to this subdivision.

(h) The commission shall determine and authorize the most efficient and equitable means for achieving all of the following:

(1) Meeting the objectives of this section.

(2) Ensuring that investment is made in new generating capacity.

(3) Ensuring that existing generating capacity that is economic is retained.

(4) Ensuring that the cost of generating capacity is allocated equitably.

(i) In making the determination pursuant to subdivision (h), the commission may consider a centralized resource adequacy mechanism among other options.

(j) For purposes of this section, "load-serving entity" means an electrical corporation, electric service provider, or community choice aggregator. "Load-serving entity" does not include any of the following:

(1) A local publicly owned electric utility.

(2) The State Water Resources Development System commonly known as the State Water Project.

(3) Customer generation located on the customer's site or providing electric service through arrangements authorized by Section 218, if the customer generation, or the load it serves, meets one of the following criteria:

(A) It takes standby service from the electrical corporation on a commission-approved rate schedule that provides for adequate backup planning and operating reserves for the standby customer class.

(B) It is not physically interconnected to the electric transmission or distribution grid, so that, if the customer generation fails, backup electricity is not supplied from the electricity grid.

(C) There is physical assurance that the load served by the customer generation will be curtailed concurrently and commensurately with an outage of the customer generation.

(END OF APPENDIX A)

APPENDIX B

Resource Adequacy Decisions – 2004 to 2009

Decision/ Proceeding	Summary
Decision (D.) 04-01-050/ Rulemaking (R.) 01-10-024	In conjunction with a long-term procurement framework for the three largest California IOUs, adopted a policy of forward procurement obligations applicable to all LSEs, including ESPs and CCAs as well as IOUs. The forward procurement obligation includes a 15% planning reserve margin (PRM). LSEs must demonstrate acquisition of 90% of the capacity needed to meet their forecast peak load plus the PRM, for the following May through September.
D.04-07-028/ R.04-04-003	Responding to the CAISO's increasing need to manage congestion and address reliability issues in Southern California, modified prior orders to make clear that reliability is not only the CAISO's job. It is also a utility responsibility to procure resources necessary to meet its load system-wide and locally.
D.04-10-035/ R.04-04-003	Accelerated implementation of the 15% PRM requirement from January 2008 to June 2006. Provided definition and clarification regarding the RA policy framework. Key elements of the decision included load forecasting protocols, resource counting conventions, month-ahead compliance showings by LSEs in addition to year-ahead showings, and a policy that resources that qualify for RA compliance purposes should be obligated to bid into the CAISO's day-ahead market if not scheduled by the LSE.
D.05-10-042/ R.04-04-003	Ordered the implementation of "system" RA program beginning in June 2006 and stated intention to establish Local RA procurement obligations beginning in 2007. Addressed several RA program implementation issues, including the nature of the RA obligation (monthly system peak), the role of the CEC in reviewing and adjusting LSE load forecasts, coordination of the RA program and CAISO operations, load forecasting and resource counting issues, standard RA contract elements, the phase-out of the ability to count non-unit specific contracts for RA showings, the "must-offer obligation" (MOO) of RA resources to be available to the CAISO, and penalties for an LSE's failure to meet RA procurement obligations.
D.06-02-007/ R.04-04-003	Removed a prohibition on reselling and re-trading import capacity rights.
D.06-04-040/ R.04-04-003	In response to applications for rehearing, modified D.05-10-042 to emphasize that the RA program in place for 2006-2008 is transitional and to clarify that the MOO provision to be included in RA contracts is an independent, RA-based requirement that does not attempt to change or alter the current Federal Energy Regulatory Commission-imposed MOO.

D.06-06-064/ R.05-12-013	Established local procurement obligations for 2007 based on a 2007 Local Capacity Requirements (LCR) study by the CAISO, and set the stage for establishing local procurement obligations in future years. Addressed local RA policy and implementation issues including LCR study methodology, allocation of LCRs to Commission-jurisdictional LSEs, aggregation of local areas for compliance purposes, the compliance filing process, coordination with the CAISO's Reliability Must Run designations, market power, waivers, and penalties for non-compliance.
D.06-07-031/ R.05-12-013	Addressed certain RA policy issues to establish clearer expectations among market participants regarding how contracts for RA resources will count towards meeting LSEs' procurement obligations. Adopted protocols for forced and scheduled outages and refined the definition of the essential elements of an RA capacity product that can be readily traded.
Resolution No. E-4017	Approved a citation program for enforcing compliance with certain RA filing requirements.
D.06-12-037 R.04-04-003	In response to various petitions for modification, modified D.05-10-042 to (1) require that RA-qualified firm liquidated damages import contracts specify a delivery point at an interconnection with the CAISO control area or a CAISO scheduling point, (2) exempt certain import contracts from the requirement that RA resources be available to the CAISO in real time, and (3) make minor clarifying wording changes.
D.07-06-029/ R.05-12-013	Established local procurement obligations for 2008 and addressed zonal transmission constraints by adopting a "Path 26 Counting Constraint."
D.08-06-031/ R.08-01-025	Established local procurement obligations for 2009, modified certain resource counting rules, and approved modifications to the compliance reporting procedure.
Resolution No. E-4195	Modified the citation program adopted by Resolution No. E-4017.
D.09-06-028/ R.08-01-025	Established local procurement obligations for 2010, modified certain resource counting rules, and addressed technical implementation issues.

(END OF APPENDIX B)

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the Notice of Availability of the filed document is current as of today's date.

Dated March 30, 2010, at San Francisco, California.

/s/ TERESITA C. GALLARDO
Teresita C. Gallardo

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to ensure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

* *

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