BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans	R.12-03-014 (Filed March 22, 2012)

COMMENTS OF THE ALLIANCE FOR RETAIL ENERGY MARKETS AND DIRECT ACCESS CUSTOMER COALITION ON TRACK 3 PROPOSED DECISION

Sue Mara
RTO ADVISORS, L.L.C.
164 Springdale Way
Redwood City, CA 94062
Telephone: (415) 902-4108
E-mail: sue.mara@rtoadvisors.com

Consultant to
ALLIANCE FOR RETAIL ENERGY MARKETS AND DIRECT ACCESS CUSTOMER COALITION

February 18, 2014

TABLE OF CONTENTS

TABLE OF AUTHORITIES

I. THE PD CORRECTLY DETERMINES THAT ALL FORECASTED DEPARTING LOAD SHOULD BE EXEMPT FROM STRANDED COST RECOVERY. 1

II. THE PD'S FINDING THAT BUNDLED PROCUREMENT IS NOT SUBJECT TO THE COST ALLOCATION MECHANISM ("CAM") REQUIRES FURTHER CLARIFICATION. 3

III. THE PD SHOULD BE MODIFIED TO NOTE THAT CALCULATIONS OF NET CAPACITY COSTS UNDER THE JOINT PARTIES PROPOSAL REQUIRE UPDATING AND FURTHER REVIEW. 7

IV. FACTUAL ERROR REQUIRING CORRECTION. 8

V. CONCLUSION. 8

ATTACHMENT A: RECOMMENDED MODIFICATIONS TO PROPOSED DECISION

TABLE OF AUTHORITIES

STATE STATUTES, CODES, REGULATIONS

Assembly Bill 57 .... 3, 6

Public Utilities Code Section 365.1 6

Public Utilities Code Section 365.1(c)(2) 3

Public Utilities Code Section 365.1(c)(2)(A) 6, 7

Public Utilities Code Section 365.1(c)(2)(A) and (B). 4

Public Utilities Code Section 454.5 6

CPUC DECISIONS, DOCKETS, RULES

Decision 02-11-022 4

Decision 06-07-029 6

Decision 07-09-044 7

Decision 08-09-012 2

Decision 13-10-040 8

Rulemaking 10-05-006 6

SB_GT&S_0120984

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans	R.12-03-014 (Filed March 22, 2012)

COMMENTS OF THE ALLIANCE FOR RETAIL ENERGY MARKETS AND DIRECT ACCESS CUSTOMER COALITION ON TRACK 3 PROPOSED DECISION

In accordance with Rule 14.3 of the Commission's Rules of Practice and Procedure, the Alliance for Retail Energy Markets[1] ("AReM") and Direct Access Customer Coalition[2] ("DACC") respectfully submit these comments on the proposed decision ("PD") issued by Administrative Law Judge ("ALJ") David M. Gamson on January 28, 2014 and subsequently updated on February 4, 2014.[3]

I. THE PD CORRECTLY DETERMINES THAT ALL FORECASTED DEPARTING LOAD SHOULD BE EXEMPT FROM STRANDED COST RECOVERY.

The PD directs investor-owned utilities ("IOUs") to include forecasts of departing load in their 10-year bundled procurement plans and exclude such forecasted load from their "future

[1] AReM is a California non-profit mutual benefit corporation formed by electric service providers that are active in the California's direct access ("DA") market. This filing represents the position of AReM, but not necessarily that of a particular member or any affiliates of its members with respect to the issues addressed herein.

[2] DACC is a regulatory alliance of educational, commercial, industrial and governmental customers who have opted for direct access to meet some or all of their electricity needs. In the aggregate, DACC member companies represent over 1,900 MW of demand that is met by both direct access and bundled utility service and about 11,500 GWH of statewide annual usage.

[3] AReM/DACC's comments and citations herein address version 3 of the PD sent by ALJ Gamson to the service list via electronic mail on February 4, 2014. Because the revised PD was released as a Word document, pagination may differ from copy to copy. Therefore, Section references are provided in addition to page cites herein.

SB_GT&S_0120985

procurement activities, and only procure for the assumed amount of their retained bundled load."[4] The PD then directs that all such forecasted departing load shall be exempt from stranded-cost recovery charges as of the date of departure assumed in the IOUs' approved bundled procurement plans.[5] AReM and DACC strongly concur and support this approach. As AReM and DACC have long contended, there is available data that allows the IOUs to make reasonable forecasts of departing load.[6] Common sense dictates that the IOUs need not procure for such forecasted departed load. If there is no IOU procurement that serves the departing load, then there can be no associated costs that are "stranded" as of the date of the assumed departure. The Commission previously approved a similar approach for municipal departing load, finding that no cost shifting occurred as a result:

> [S]ince there are no resources or associated costs in the forecast year related to the load departing in that year, there is no cost shifting to bundled customers when these departing customers leave.[7]

As AReM and DACC have previously pointed out, continuing the status quo in which non-bypassable stranded cost charges are applied to load that was forecast to depart should be viewed by the Commission as impermissible cost-shifting from bundled customers to retail choice customers.[8] Accordingly, the PD corrects this long-standing inequity and should be adopted without modification. DACC and AReM look forward to working with the Commission to ensure this new policy is properly reflected in the IOUs' calculations.

---

[4] PD, Section 4.2.3, pp. 14-15.

[5] PD, Section 4.2.3, pp. 14-15. See also, PD, Ordering Paragraph 1, pp. 66-67.

[6] Reply of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition to Track III Comments, R.12-03-013, May 10, 2013, pp. 8-9.

[7] D.08-09-012, pp. 24-25.

[8] Reply of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition to Track III Comments, R.12-03-013, May 10, 2013, pp. 8-9.

II. THE PD'S FINDING THAT BUNDLED PROCUREMENT IS NOT SUBJECT TO THE COST ALLOCATION MECHANISM ("CAM") REQUIRES FURTHER CLARIFICATION.

AReM and DACC appreciate the PD's attempt to clarify Commission policy on CAM as it relates to bundled customer procurement. However, the clarifications are imprecise and fall short of providing what AReM and DACC believe to be required by statute.[9] AReM and DACC provide the following recommendations to remove imprecision and conform to statutory requirements.

First, the PD states that bundled procurement undertaken pursuant to an IOU's AB 57 bundled procurement plan is "normally not subject to CAM." [10] Indeed, AReM and DACC are hard-pressed to think of any example in which the statute governing CAM procurement would allow such AB 57 bundled procurement *to* be subject to CAM and not run afoul of the law. Public Utilities Code Section 365.1(c)(2) is explicit that CAM procurement must benefit *all* customers in the IOU's service territory, so procurement undertaken specifically to meet bundled customers' need would obviously fail this test. In fact, *any* procurement to meet bundled customers' needs, whether or not it is undertaken pursuant to an AB 57 procurement plan, is not and should not be subject to CAM treatment. The PD should be modified to make this crystal clear, as shown in Attachment A.

Second, the PD states:

> Routine procurement to meet a utility's near-term resource adequacy requirements for its bundled service customers would not normally be subject to CAM, nor would such procurement by a non-IOU LSE. On the other hand, long-

---

[9] In D.11-05-005 (pp. 6-7), the Commission found that it could determine when the "statutorily-specified conditions" for imposing CAM had been met by a particular procurement, but deferred establishing any such criteria needed to make the CAM determination, and instead committed to developing "the criteria the Commission will use in making this determination … later in this or a successor proceeding." The Commission has not yet established any criteria for CAM determinations.

[10] PD, Section 8.3.3, p. 48.

SB_GT&S_0120987

> term utility procurement undertaken to develop new or expanded infrastructure to meet system or local reliability needs in its distribution service area will typically be subject to CAM, and the RA value of such resources will be allocated to all LSEs. To our knowledge, ESPs and CCAs have not engaged in such long-term infrastructure procurement, except perhaps in the RPS context. IOUs, ESPs and CCAs each meet their own individual RPS procurement requirements, and the costs of those contracts are not normally subject to CAM treatment.[11]

It also states:

> On the other hand, procurement that a utility is authorized or directed to undertake in the "system track" of the LTPP, to meet local or system (including flexibility) reliability needs, will ordinarily be subject to the CAM.[12]

Three very serious flaws are reflected in these excerpts. The first is that this rationale ignores the statutory requirement that any such CAM procurement must benefit *all customers* in the utility's service area.[13] Unfortunately, the PD fails to make any reference to this "benefitting customers" requirement with respect to procurement that it deems to be CAM -eligible. As noted above, for example, utility procurement undertaken to meet the needs of the bundled customers, "benefits" those bundled customers alone. Thus, such procurement would NOT be subject to CAM, regardless whether some tangential local or system reliability benefits accrue from the procurement.

The Commission has previously determined that allocating costs based on indirect societal benefits was arbitrary and speculative, stating: "Attempting to assign a charge to [direct access] customers *based solely on indirect societal benefits* would be arbitrary and speculative."[14] The relevance here is clear – bundled customers are the *direct beneficiaries* of the IOUs' bundled procurement and any incidental reliability benefits to "all" are indirect

---

[11] PD, Section 8.3.3, p. 49.

[12] PD, Section 8.3.3, pp. 48-49.

[13] Public Utilities Code Section 365.1(c)(2)(A) and (B).

[14] D.02-11-022, p. 57

SB_GT&S_0120988

societal benefits at best. No rational policy case can be made to impose CAM costs on direct access customers for procurement by the IOUs to meet the needs of their bundled customers. Unless and until the Commission determines that there is a real and direct benefit to retail choice customers from a specific utility investment, it cannot and should not be affording CAM treatment to those projects. When the suppliers who serve retail choice customers are in full compliance with all established reliability requirements, then there is no basis upon which to assign CAM charges to their customers.

The second flaw is that these statements seem to suggest that non-IOU LSEs could seek CAM treatment for their procurement when it enhances system or local reliability. That suggestion also runs afoul of the underlying statute which affords CAM treatment to procurement authorized and directed by the Commission – since the Commission does not dictate or approve investments by non-IOU LSEs, the statute would not permit CAM treatment for their investments. Moreover, the non-IOU LSEs that AReM represents have no interest in having the costs or benefits of their investments spread to customers they do not serve. Indeed, it is the antithesis of choice to suggest that customers who are not served by a particular supplier must nevertheless pay the costs of that supplier's procurement – or that a supplier who has made competitive investments to serve its customers must share the benefits of that investment with customers it does not serve.

Third, the PD seems to set forth a new policy that all procurement directed in the "system track" of the LTPP is *de facto* subject to CAM. This approach is unsupported by the statute and blatantly unfair to retail choice customers, who deserve rational and careful analysis by this Commission before being burdened with additional costs – costs that the Commission itself has

SB_GT&S_0120989

identified as undermining competitive markets.[15] Indeed, the applicable statute for CAM procurement requires an independent Commission determination on each proposed utility procurement[16] whereas an entirely separate statute, established by AB 57, governs the IOUs' long-term planning process to meet their bundled needs.[17] Between these two sections of the Public Utilities Code there is neither reference to nor concept of a "system plan" as something separate, distinct or, indeed, *required* by the law.

In fact, the concept of a "system" and "bundled" track are artifices that were implemented for Commission convenience and were never intended to dictate Commission policy on cost recovery. After the passage of AB 57 in 2002, the Commission began directing the IOUs to plan to meet their bundled loads reliably. Later in the process, the Commission elected to separate the long-term planning process into "system/local" and "bundled" plans.[18] In this current LTPP proceeding, we have seen a number of tracks, including Track 1 addressing local needs only in Southern California, Track 2 to address "system" needs (which was cancelled), and Track 4 to address replacing San Onofre Nuclear Generating Station ("SONGS"). As noted above, the pertinent Public Utilities Code Sections 454.5 and 365.1 contain no requirement for separate tracks or for separate Commission decisions on types of need (*i.e.,* system, local, bundled). While such separate procurement tracks can certainly be pursued by the IOUs and the Commission, they cannot replace or supersede the Commission's statutory

---

[15] For example, when the Commission first elected to impose the CAM in D.06-07-029 (pp. 24-25), it expressed concern that the CAM it was adopting might afford " too much price guarantee and risk protection for the IOUs," which could "undermine the development of a more competitive market."[15]

[16] Public Utilities Code Section 365.1(c)(2)(A): " … in the event that the commission authorizes, ***in the situation of a contract*** with a third party, or orders, ***in the situation of utility-owned generation***, an electrical corporation to obtain generation resources … "(emphasis added).

[17] Public Utilities Code Section 454.5.

[18] The first such bifurcation we could find appears in R.10-05-006, pp. 2 and 9.

SB_GT&S_0120990

obligations to determine when the specific utility procurement meets the "reliability need for the benefit of all customers" in the utility's service territory.[19] Accordingly, AReM and DACC respectfully request modifications to Section 8.3.3 of the PD to correct imprecise references and properly reflect statutory requirements, as set forth in Appendix A.

III. THE PD SHOULD BE MODIFIED TO NOTE THAT CALCULATIONS OF NET CAPACITY COSTS UNDER THE JOINT PARTIES PROPOSAL REQUIRE UPDATING AND FURTHER REVIEW.

The PD notes that AReM and DACC requested that the Joint Parties Proposal ("JPP") adopted in D.07-09-044 be reexamined, so that the full value of energy and other products is netted from the contract price in setting the net capacity cost that is reflected in CAM.[20] Specifically, AReM and DACC explained that the proxy calculation for net capacity costs in the JPP includes only one ancillary service, non-spinning reserves, whereas there are, in fact, *four* ancillary services that are currently traded (Regulation Up, Regulation Down, Non-Spinning Reserves and Spinning Reserves)[21] and two more ancillary services that can be provided through separate contracting mechanisms (Voltage Support and Blackstart Capability). Moreover, the CAISO is currently developing a flexible ramping product that could provide additional revenue to resources able to provide the service, and new flexible capacity requirements are being implemented for the 2015 resource adequacy compliance year. In short, the JPP calculation is outdated and should be reexamined and refreshed to reflect current market conditions.

Thus, the PD mistakenly refrains from taking any action to update the calculation of net capacity costs in the JPP. To remedy this oversight, DACC and AReM respectfully request that

---

[19] Public Utilities Code Section 365.1(c)(2)(A).

[20] PD, Section 8.4.2, p. 51.

[21] Track III Comments of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition, R.12-03-014, April 26, 2014, p. 15.

the PD be modified to direct Staff to evaluate the JPP calculation immediately to ensure that the calculated net capacity costs associated with CAM resources are accurate and fair. Appendix A provides the recommended revisions to implement this change.

IV. FACTUAL ERROR REQUIRING CORRECTION.

The PD includes one factual error requiring correction. The PD lists types of "centralized procurement" conducted by the IOU.[22] Energy storage is included in error and should be removed. The recent Commission decision on energy storage set a procurement target for each LSE, including ESPs and CCAs, and did not authorize centralized procurement by the IOUs on behalf of "all benefitting customers."[23] Therefore, AReM and DACC respectfully request that the PD be corrected, as shown in Attachment A, by removing the reference to energy storage as a type of centralized procurement authorized by the Commission.

V. CONCLUSION.

AReM and DACC respectfully request modifications to the PD as discussed above and summarized here. Attachment A contains specific modification to the PD, and its Conclusions of Law and Ordering Paragraphs.

- The PD's determination that departing load should be forecast by the utilities as part of their bundled procurement plans and exempt from future stranded cost recovery is reasonable and should be adopted without modification.
- The PD's determination that bundled procurement is not subject to CAM should be adopted and clarified as recommended. However, the PD's policy statement

---

[22] PD, Section 8.3.1, p. 43.

[23] D.13-10-040, Ordering Paragraphs 2 and 4, p. 27.

on CAM procurement should be clarified to correct imprecise language and reflect statutory requirements.

- The PD should be modified to require th e calculation of net capacity costs in the JPP to be updated to reflect current market conditions.
- The factual error in the PD regarding types of centralized procurement by the IOUs should be corrected.

Respectfully submitted,

Sue Mara
RTO ADVISORS, L.L.C.
164 Springdale Way
Redwood City, CA 94062
Telephone: (415) 902-4108
E-mail: sue.mara@rtoadvisors.com

Consultant to
ALLIANCE FOR RETAIL ENERGY MARKETS AND DIRECT ACCESS CUSTOMER COALITION

February 18, 2014

SB_GT&S_0120993

ATTACHMENT A

RECOMMENDED MODIFICATIONS TO PROPOSED DECISION

Corrections to Body of PD, Section 8.3.1, p. 43:

The Commission administers a variety of centralized procurement programs, each with impacts to bundled and non-bundled benefitting customers. The Commission may create more programs of that nature in the future, and allocate further costs to benefitting customers. No Commission determinations have been made as to how the different types of centralized procurement (CHP procurement, demand response, **and** new generation resources pursuant to LTPP~~**, and the recently approved energy storage procurement mandate**~~) relate and how all these types should be evaluated in combination with the goal of providing cost effective reliability and adherence to the Commission's Loading Order.

Corrections to Body of PD, Section 8.3.3, pp. 48-49:

Because various parties have continued to question the basis upon which the Commission determines the eligibility of a particular resource procurement for CAM treatment, we take this opportunity to explain our policy further. Bundled procurement undertaken pursuant to a utility's AB 57 bundled procurement plan is ~~**normally**~~ not subject to the CAM, **nor is any other bundled procurement**. On the other hand, procurement that a utility is authorized or directed to undertake in ~~**the "system track" of**~~ the LTPP, ~~**to**~~ **which the Commission determines is needed to** meet local or system (including flexibility) reliability needs **for the benefit of all customers**, will ordinarily be subject to the CAM. Thus, the answer to the fourth question in this section: "At what stage in procurement should procurement be deemed CAM eligible, and what criteria should govern Commission decision[s] regarding CAM allocation?" follows directly from these basic principles. When the Commission in the LTPP (or other appropriate proceeding) authorizes or directs a utility to procure resources **that it determines are needed** to meet system or local reliability needs **for the benefit of all customers**, the CAM applies. Absent such authorization or direction, CAM does not apply, unless otherwise stated in a specific

SB_GT&S_0120994

Commission decision. Since bundled plans **do not benefit all customers** ~~**rarely if ever direct particular procurements**~~, this distinction should be reasonably transparent to all parties.

Addition to Conclusion of Law 10

10. Energy auctions should no longer be required to net capacity costs for CAM facilities. Instead all utilities should use the mechanism adopted in the JPP to set the residual capacity costs that would be allocated to benefitting customers. **Energy Division shall reexamine this mechanism to ensure that all sources of revenue for energy and ancillary services are incorporated into the calculation**.

Addition to Ordering Paragraph 4

4. Energy auctions shall no longer be required to net capacity costs for facilities subject to the Cost Allocation Mechanism. Instead Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall use the mechanism adopted in Decision 07-09-044, known as the "Joint Parties' Proposal," to set the residual capacity costs that would be allocated to benefitting customer. **Within 90 days after the effective date of this proceeding, Energy Division shall reexamine this mechanism to ensure that all sources of revenue for energy and ancillary services are incorporated into the calculation**.

SB_GT&S_0120995