Docket No.: R.12-03-014

Exhibit No.:

Date: June 25, 2012

Witnesses: Sue Mara and Mark Fulmer

TESTIMONY ON BEHALF OF THE ALLIANCE FOR RETAIL ENERGY MARKETS, DIRECT ACCESS CUSTOMER COALITION, AND MARIN ENERGY AUTHORITY

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I. INTRODUCTION AND WITNESS QUALIFICATIONS

A. Sue Mara

Witness: Sue Mara

Q. Ms. Mara, please state your name and business address.

A. My name is Sue Mara and my address is 164 Springdale Way, Redwood City, California. I have been active in energy and electricity markets for more than 35 years. Since 2002, I have been Principal at RTOAdvisors, L.L.C., which focuses on promoting competitive wholesale and retail markets. I have provided consulting services on regulatory matters to a variety of wholesale and retail clients on California and western energy markets. I provide my full witness qualifications in Attachment A.

Q. Have you previously provided testimony at the California Public Utilities Commission?

A. Yes. I have provided testimony on behalf of the Alliance for Retail Energy Markets ("AReM") in the proceeding addressing the utilities' demand response program applications in 2008 (A.08-06-001 to -003), the Long-Term Procurement Plans ("LTTP") proceeding (R.06-02-013), and in the Confidentiality proceeding (R.05-06-040). I have also provided testimony on behalf of AReM and the Direct Access Customer Coalition ("DACC") regarding Pacific Gas and Electric Company's ("PG&E") recent application for approval of Smart Grid Pilots (A.11-11-017). I have also testified before the Federal Energy Regulatory Commission. Attachment A lists the prepared testimony I have submitted since 1997.

B. Mark Fulmer

<u>Witness</u>: Mark Fulmer

Q. Mr. Fulmer, please state your name and business address.

A: My name is Mark E. Fulmer. I am a Principal at MRW & Associates, LLC ("MRW"). MRW is an energy consulting firm founded in 1986 that specializes in power and gas market assessments, regulatory matters, litigation support, expert witness testimony, contract review, and negotiations. My business address is 1814 Franklin Street, Suite 720, Oakland, California. My professional and educational background is provided in Attachment A.

Q: Have you previously testified before the California Public Utilities Commission?

A: Yes. I have previously testified before the California Public Utilities Commission ("CPUC" or "Commission") on behalf of DACC, AReM, Debenham Wind, Strategic Energy and Constellation NewEnergy, and the City and County of San Francisco ("CCSF"). I have also submitted testimony in proceedings before the Federal Energy Regulatory Commission and state utility commissions in Arizona, Hawaii, Pennsylvania and Rhode Island.

C. Interests of the Parties

<u>Witness</u>: Sue Mara

Q. On whose behalf are you testifying?

A. We are testifying on behalf of AReM, DACC, and the Marin Energy Authority ("MEA"). AReM is a California mutual benefit corporation whose members are electric service providers ("ESPs") that provide direct access ("DA") service to retail end-use customers throughout the state. DACC is a regulatory alliance of educational, commercial, industrial and governmental customers who have opted for DA service for some or all of their loads. MEA is a joint powers agency and public entity organized under the laws of the state of California and operator of California's first Community Choice Aggregation ("CCA") program, which began serving customers on May 7, 2010. MEA's current membership includes all of Marin County.

Q. Please explain the interests of AReM, DACC and MEA in this proceeding.

A. AReM and DACC represent ESPs and DA customers. MEA represents the only operating CCA in California. ESPs and CCAs are load-serving entities ("LSEs") and as such must procure energy, capacity, and ancillary services to meet their load, and must comply with System and Local Resource Adequacy ("RA") requirements, the Renewable Portfolio Standard ("RPS"), and applicable provisions of the Greenhouse Gas ("GHG") Emission Reduction requirements. When the Commission authorizes the Investor-Owned Utilities ("IOUs") to procure resources whose costs are allocated pursuant to the Cost Allocation Mechanism ("CAM") adopted in Commission Decision ("D.") 06-07-029, as modified by D.11-05-005, ESPs and CCAs lose management and control of their own procurement with respect to both the type of resources procured and the cost of those resources. In addition, requiring ESPs and CCAs to incorporate utility procurement into their own procurement plans hinders them from offering the specific products and services that their customers want, and therefore undermines the competitive market. In fact, the Commission acknowledged competitive concerns when it established the CAM.[1] Consequently the Commission should strive to minimize use of the CAM to situations specifically required by statute only.

[1] D.06-07-029, pp. 23-25.

Accordingly, AReM, DACC, and MEA propose herein to establish clear guidelines as to when the CAM can be applied and how CAM-eligible utility procurement costs are to be reasonably calculated and fairly allocated to all benefiting customers. Further, AReM, DACC, and MEA seek Commission approval of a process by which ESPs and CCAs can opt-out of CAM procurement.

II. SUMMARY CONCLUSIONS AND RECOMMENDATIONS

Q. What are the conclusions of AReM, DACC and MEA regarding changes to Commission CAM policy and practice with respect to Senate Bills 695 and 790?

<u>Witness</u>: Sue Mara

A. As discussed in detail in Chapter III of this testimony:

- SB 695 and SB 790 are evidence that the Legislature intends for the Commission to ensure fair IOU cost recovery, but in a manner that does not unnecessarily impede or compromise the competitive retail choice market.
- SB 695 specified conditions that Commission must meet in authorizing CAM procurement by the IOUs; these conditions are to be considered and adopted in this proceeding.
- SB 695 modified CAM procurement policy and cost allocation methods, but the implementation details of the cost allocation methods were not fully addressed by the Commission in D.11-05-005 and are to be considered and adopted in this proceeding.
- SB 790 placed the burden on the Commission to demonstrate that any proposed CAM procurement by the IOUs meets the statutory requirements, which includes an

obligation to identify and apply stringent criteria before approving CAM procurement.

- SB 790 added new Commission obligations for cost allocation relative to CAM procurement and treatment of CCAs.

- SB 790 directs the Commission to implement the new CAM rules by no later than January 1, 2013.

- The Commission has previously determined that its CAM review must be comprehensive and evaluate CAM modifications in the context of relevant provisions of the Public Utilities ("P.U.") Code.

Q. What are the summary recommendations of AReM, DACC and MEA for establishing a Commission process to authorize CAM procurement by the IOUs?

Witness: Sue Mara

A. As discussed in detail in Chapter IV of this testimony:

- The Commission's goal should be to minimize CAM procurement, while continuing to ensure that reliability requirements are met, in order to fulfill its commitment to competition and customer choice.

- Ordered CAM procurement should be the exception, not the rule.

- Criteria are proposed that the Commission would apply in determining whether an IOU's proposed CAM procurement met statutory requirements; the criteria achieve the twin goals of meeting statutory requirements and enabling retail choice.

- The Commission must determine that each criterion has been met <u>before</u> it can authorize a particular CAM procurement, which will require the IOU and the California Independent System Operator ("CAISO") to provide evidence to demonstrate that the project identified in the IOU's application meets the Commission-defined reliability need and cannot be reasonably met by any other existing or new resource, including demand response and energy efficiency.

- The Commission would implement and follow a two-stage process, in which it would: (1) identify the megawatts of unmet need that may be subject to future CAM procurement; and (2) apply the defined criteria to an IOU's application for approval of a CAM project.

- In determining unmet need potentially subject to CAM procurement, the Commission would first enforce P.U. Code Section 454.5 and incorporate cost causation principles, which require the IOUs to procure to meet the load, load growth and peak load characteristics of their bundled utility customers over the long term, including procurement of new generation resources; IOU procurement for bundled customer load is not subject to CAM.

- IOU contracts or projects that replace existing plants or power purchase agreements ("PPAs") used primarily to serve bundled load are to be incorporated into the IOU's bundled load needs for which CAM is not applicable.

Q. If the Commission authorizes CAM procurement, what are the summary recommendations of AReM/DACC/MEA for calculation of the CAM payment and allocation of associated benefits?

<u>Witness</u>: Mark Fulmer

A. As discussed in detail in Chapter V of this testimony, if the Commission finds that CAM treatment is appropriate for a specific utility procurement, AReM/DACC/MEA have the following recommendations:

- The net capacity costs calculation from the Joint Parties Proposal[2] must be modified to better reflect the increased ancillary service value and value of other products and services that the new PPAs or utility-owned generation ("UOG") plants will be able to provide.
- Because of how utility assets are depreciated, the net capacity costs calculation for UOG plants should start with the levelized fixed costs rather than the fixed revenue requirement. To do otherwise would overvalue the plants' capacity in early years and undervalue it in later ones.
- The CAM cost associated with any PPA or UOG asset should be capped.
- The net capacity cost calculation can conceivably result in net capacity costs that are less than zero. If that occurs, the negative amount should be passed through to all benefiting customers.

Q. What are the summary recommendations of AReM, DACC and MEA for a mechanism by which ESPs and CCAs can opt-out of the CAM?

Witness: Sue Mara

A. As discussed in detail in Chapter VI of this testimony:

- The Commission has acknowledged the legitimate need to establish an LSE Opt-Out from CAM procurement in previous decisions.

[2] The Joint Parties' Proposal is an alternative to the energy auction that calculates net capacity costs on a proxy basis by imputing energy costs and revenues retroactively based on day-ahead market prices. (D.07-09-044, Appendix A)

- LSE Opt-Out provides market incentives for ESPs and CCAs to enter into multi-year contracts for RA capacity, thereby reducing the need for CAM procurement by the IOUs; the current CAM approach provides no such incentives.
- LSE Opt-Out is consistent with SB 695 and required to comply with SB 790.
- Once the Commission determines the unmet need that may be subject to future CAM procurement and the timing of that need, an ESP or CCA would have the option to request an opt-out from the prospective CAM procurement.
- To qualify for an opt-out, an LSE would make a showing to the Commission that it has procured adequate generation resources for a 5-year period; the 5-year period is reasonable to address anti-competitive concerns and other considerations.
- Three types of opt-out options are proposed, chosen at the election of the ESP or CCA: (1) Load-Ratio Share Opt-Out; (2) Load-Based Opt-Out; and (3) Customer-Based Opt-Out.
- The LSE would be required to request the opt-out before the IOUs submit any proposed CAM projects to the Commission for approval, as described herein, to eliminate the potential for stranded-cost claims by the IOUs if an ESP or CCA were allowed to opt-out after the CAM project was approved or operational.

III. MODIFICATIONS TO THE CAM REQUIRED BY SENATE BILLS 695 AND 790

Witness: Sue Mara

Q. What is the purpose of this section of the testimony?

A. This section describes the CAM-related provisions of Senate Bills ("SB") 695 and 790 that apply when the Commission is considering whether to authorize procurement of CAM resources by the IOUs. The referenced provisions affect the Commission's process to follow and the criteria to apply when authorizing any such procurement, as well as proper calculation of the CAM payment and allocation of associated benefits. SB 695 was signed into law in 2009.[3] SB 790 was enacted in 2011 to clarify Commission and IOU requirements relative to CCAs.[4] SB 790 modified some of the CAM provisions adopted in SB 695 and added other relevant provisions that provide Commission guidance on procurement issues. In the next two sections, I discuss each of these bills and the P.U. Code sections that they enacted.

A. Senate Bill 695

Q. What is the background of the CAM and what did SB 695 modify?

A. The Commission adopted the CAM in D.06-07-029 and determined therein that the mechanism was required by P.U. Code Section 380 (g),[5] which had been enacted in 2005 by Assembly Bill ("AB") 380[6] and provided guidance to the Commission in establishing its RA program for LSEs. In 2009, the Legislature enacted SB 695, which added P.U. Code Section 365.1 (c) (2) and provided direction to the Commission on the application of the CAM to "all benefiting customers," as follows:

> 365.1 (c) (2) (A) Ensure that, 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 that the commission determines are needed to meet system or local

[3] Stats 2009, Ch 337.
[4] Stats 2011, Ch 599.
[5] D.06-07-029, pp. 40-43.
[6] Stats 2005, Ch. 357.

area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory, the net capacity costs of those generation resources are allocated on a fully nonbypassable basis consistent with departing load provisions as determined by the commission, to all of the following:

(i) Bundled service customers of the electrical corporation.

(ii) Customers that purchase electricity through a direct transaction with other providers.

(iii) Customers of community choice aggregators.

(B) The resource adequacy benefits of generation resources acquired by an electrical corporation pursuant to subparagraph (A) shall be allocated to all customers who pay their net capacity costs. Net capacity costs shall be determined by subtracting the energy and ancillary services value of the resource from the total costs paid by the electrical corporation pursuant to a contract with a third party or the annual revenue requirement for the resource if the electrical corporation directly owns the resource. An energy auction shall not be required as a condition for applying this allocation, but may be allowed as a means to establish the energy and ancillary services value of the resource for purposes of determining the net costs of capacity to be recovered from customers pursuant to this paragraph, and the allocation of the net capacity costs of contracts with third parties shall be allowed for the terms of those contracts.

(C) It is the intent of the Legislature, in enacting this paragraph, to provide additional guidance to the commission with respect to the implementation of subdivision (g) of Section 380, as well as to ensure that the customers to whom the net costs and benefits of capacity are allocated are not required to pay for the cost of electricity they do not consume.

In very brief summary, Section (A) of the code specifies the conditions under which the Commission is permitted to authorize CAM and that the CAM payment is the "net capacity costs." Section (B) provides guidance on how the "net capacity costs" are to be calculated and allocated and specifies that all customers paying the "net capacity costs" must also receive the associated RA benefits. Finally, Section (C) requires that customers paying for CAM resources are not required to pay for the electricity "they do not consume." In addition, the Legislature modified this section of the P.U. Code in 2011 by enacting SB 790, which added a new Section (B), as discussed below.

Q. Has the Commission addressed how SB 695 modified the CAM?

A. Yes. In D.11-05-005, the Commission made an initial determination of modifications to the CAM established in D.06-07-029 that were required by SB 695. However, the Commission identified several key issues as necessary elements of the CAM, but left them to later Commission determinations.

Q. Please explain.

A. In D.11-05-005, the Commission determined, among other things, that SB 695 removed the utilities' ability to elect whether or not to seek CAM treatment for a particular resource.[7] The Commission also found that SB 695 leaves it to the Commission to determine when the "statutorily-specified conditions" have been met such that the CAM would be permitted to apply to an IOU's procurement.[8] However, the Commission 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."[9]

Q. Has the Commission developed the necessary criteria?

A. Not yet. The criteria for proper application of the CAM were not addressed in that Rulemaking ("R.") 10-05-006. However, application of the CAM pursuant to SB 695 and D.11-05-005 is included within the scope for Track 1 of this current Long-Term Procurement Plan proceeding, as is the issue of whether the CAM should be modified at this time.[10] Thus, this is the appropriate proceeding for the Commission to determine the criteria it will use to apply the CAM, as required by SB 695. AReM/DACC/MEA provide

[7] D.11-05-005, Ordering Paragraph number 1, p. 19.
[8] D.11-05-005, p.6.
[9] D.11-05-005, p. 7.
[10] *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge*, R.12-03-014, May 17, 2012, items number 8 and 9, p. 6.

recommended criteria and a proposed process to determine when the CAM should be properly applied in the Chapter IV of this testimony.

Q. Did the Commission acknowledge other aspects of its policies in D.11-05-005 that needed to be revised as a result of SB 695?

A. Yes. The Commission explained that D.11-05-005 "narrowly modified" existing rules and processes "to ensure compliance with the resource adequacy provisions of SB 695" and concluded that issues clearly remained to be resolved.[11] In addition to the policy for setting the net capacity price for the CAM discussed below, the specific issues listed included:

1. The development of policies and processes for distinguishing between system and bundled resource needs, and related cost allocation; and
2. Whether there should be a test of "who benefits" under SB 695, and if so, the construction of such a test."[12]

The Commission also states its intention to "further develop the record in later phases of this proceeding in order to resolve these issues."[13] As mentioned above, there was no further activity on these issues in that proceeding, but they are now included within the scope of this proceeding. Accordingly, AReM/DACC/MEA propose criteria and a process for resolving these issues in Chapter IV of this testimony.

Q. Did SB 695 also modify how the net capacity price for the CAM was to be determined?

[11] D.11-05-005, p. 16.
[12] D.11-05-005, p. 16.
[13] D.11-05-005, p. 17.

A. Yes. SB 695 modified the Commission's previous policy to require an energy auction to set the net capacity price that would be charged to all benefiting customers.[14] In D.11-05-005, the Commission determined that SB 695 allows the Commission to choose to use an auction, but does not require that an auction be used.[15] The Commission stated that the energy auction mechanism adopted in D.07-09-004 "may need to be revised" and that it intended to address "[c]onsideration of non-auction processes and revisions to the auction methodology … in later phases of this proceeding or a successor proceeding."[16]

Q. Did the Commission consider non-auction processes and revisions to the auction methodology as promised?

A. No. These issues were not addressed in that rulemaking, R.10-05-006. However, the scope for Track 1 of this LTPP proceeding includes proper application of the CAM pursuant to SB 695 and D.11-05-005 as well as whether the CAM should be modified at this time.[17] Thus, in addition to determining the criteria to use in applying the CAM, the Commission also intended to determine in this proceeding whether changes are needed to the current mechanisms used for setting the net capacity price for the CAM. At present, the predominant approach for setting the net capacity price seems to be "non-auction processes."[18] Accordingly, Mr. Mark Fulmer's testimony provides recommendations in Chapter V to improve such processes in accordance with D.11-05-005.

[14] P.U. Code Section 365.1 (c) (2) (B), as shown above, before being amended by SB 790.
[15] D.11-05-005, p. 13.
[16] D.11-05-005, p. 14.
[17] *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge*, R.12-03-014, May 17, 2012, items number 8 and 9, p. 6.
[18] On April 16, 2012, the IOUs and L. Jan Reid filed in R.10-05-006 a Petition to Modify the energy auction decision, D.07-09-044, to eliminate two specific types of auctions required in the decision explaining that no market exists for these products. The Commission has not yet acted on the Petition.

B. Senate Bill 790

Q. Did SB 790 affect the Commission's CAM policies?

A. Yes. SB 790 was signed into law on October 8, 2011 and made a number of changes to Section 365.1 (c) (2), the CAM portion of the P.U. Code, as well as to several other relevant provisions of the P.U. Code.

Q. What changed in P.U. Code Section 365.1 (c) (2)?

A. SB 790 added one major section to the code:

> 365.1 (c) (2) (B) If the commission authorizes or orders an electrical corporation to obtain generation resources pursuant to subparagraph (A), the commission shall ensure that those resources meet a system or local reliability need in a manner that benefits all customers of the electrical corporation. The commission shall allocate the costs of those generation resources to ratepayers in a manner that is fair and equitable to all customers, whether they receive electric service from the electrical corporation, a community choice aggregator, or an electric service provider.

Subsequent paragraphs were renumbered to accommodate this new text.

This added paragraph requires action by the Commission to "ensure" that the resources it authorizes for CAM procurement meet specific reliability needs that "benefit all customers" <u>and</u>, if the Commission makes that determination, that the associated costs are allocated in a "fair and equitable" manner to all such customers. Consequently, SB 790: (1) places the burden on the Commission to demonstrate that CAM procurement meets those statutory requirements for such procurement, thereby requiring the Commission to set criteria by which it will make the determination to authorize CAM procurement by the IOUs (as the Commission previously found in D.11-05-005); and (2) adds a new requirement that the associated cost allocation be "fair and equitable" to all the customers paying the CAM.

Q. Did SB 790 make any other relevant changes?

A. Yes. SB 790 changed portions of P.U. Code Section 380 and P.U. Code Section 366.2, which are also relevant to this proceeding. Section 380 enacts Resource Adequacy ("RA") requirements for LSEs, among other things, and SB 790 added Section 380 (b) (4), which established a new Commission objective that it must meet in setting RA requirements for LSEs. Specifically, Section 380 (b) (4) provides that the Commission must: "Maximize the ability of community choice aggregators to determine the generation resources used to serve their customers." SB 790 also added this same requirement to Section 380 (h) (5), which enumerates the Commission's obligations to "determine the most efficient and equitable means" to achieve the stated requirements with respect to its RA program.

Q. What were the relevant changes to P.U. Code Section 366.2 enacted by SB 790?

SB 790 added new provisions to P.U. Code Section 366.2 to make clear that CCAs are responsible for their own generation procurement, that prohibit cost shifting between CCA and bundled utility customers, and to ensure that non-bypassable charges to CCA customers are not generally allowed unless the associated benefits are allocated to the CCAs and/or their customers.

The additions to P.U. Code Section 366.2 (a) address cost shifting and CCA generation procurement, as follows:

> (4) The implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation.
>
> (5) A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers, except where other generation procurement arrangements are expressly authorized by statute.

The additions to P.U. Code Section 366.2 (g) and (k) address allocation of benefits and non-bypassable charges, as follows:

> (g) Estimated net unavoidable electricity costs paid by the customers of a community choice aggregator shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.
>
> (k) (1) Except for nonbypassable charges imposed by the commission pursuant to subdivisions (d), (e), (f), and (h), and programs authorized by the commission to provide broader statewide or regional benefits to all customers, electric service customers of a community choice aggregator shall not be required to pay nonbypassable charges for goods, services, or programs that do not benefit either, or where applicable, both, the customer and the community choice aggregator serving the customer.

Q. Did the Legislation provide guidance on when the Commission is required to implement the provisions in the statute?

A. Yes. SB 790 added a new P.U. Code Section 707, which included the following guidance:

> 707 (a) Not later than March 1, 2012, the commission shall institute a rulemaking proceeding for the purpose of considering and adopting a code of conduct, **associated rules**, and enforcement procedures, to govern the conduct of the electrical corporations relative to the consideration, formation, and implementation of community choice aggregation programs authorized in Section 366.2. (emphasis added)

The "associated rules" cover the modifications to P.U. Code Section 365.1, which addresses CAM procurement, as well as relevant P.U. Code Sections 380 and 366.2 discussed above. Moreover, P.U. Code Section 707 (b) requires that "the code of conduct, associated rules, and enforcement procedures are implemented by no later than January 1, 2013." Therefore, the Legislature clearly intended that the Commission move forward expeditiously to implement the law.

Q. Has the Commission begun implementing SB 790?

A. Yes. On February 16, 2012, the Commission initiated a new Order Instituting Rulemaking ("OIR") to address modifications to its policies and practices required by SB 790.[19] AReM, DACC and MEA along with other interested parties, referred to as the CCA Alliance, filed joint comments on the scope of the OIR urging the Commission to address the modifications to the CAM directed by SB 790 within the scope of the CCA rulemaking (R.12-02-009).[20] The parties also requested that the Commission initiate activity on the CAM issues in June 2012 and issue a final decision by November 2012.[21] However, no prehearing conference has been set and no scoping memo issued. Consequently, in order to ensure that the issue of establishing the criteria for the application of CAM is addressed as soon as possible, I am assuming that CAM issues raised in SB 790 will be addressed in Track 1 of this LTPP proceeding. The Scoping Memo in this proceeding states that CAM issues will be addressed here, unless R.12-02-009, established to implement SB 790, decides to take them up.[22]

Q. Taken together, how do you interpret these changes enacted by SB 790?

A. The Legislature intended to ensure that CCAs can fairly compete and that all retail choice providers are treated equitably in the implementation and allocation of non-bypassable charges, such as the CAM. I discuss below where these provisions are applicable.

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[19] *Order Instituting Rulemaking Pursuant to Senate Bill No. 790 to Consider and Adopt a Code of Conduct, Rules and Enforcement Procedures Governing the Conduct of Electrical Corporations Relative to the Consideration, Formation and Implementation of Community Choice Aggregation Programs*, R.12-02-009, February 16, 2012.
[20] *Opening Comments of the Marin Energy Authority, San Joaquin Valley Power Authority, South San Joaquin Irrigation District, City of Santa Cruz, The Climate Protection Campaign, Direct Energy, LLC., Noble Americas Energy Solutions LLC, Constellation NewEnergy, Inc., Alliance for Retail Energy Markets and Direct Access Customer Coalition Regarding the Rulemaking Issued Pursuant to Senate Bill 790 (CCA Alliance),* R.12-02-009, March 26, 2012, pp. 21-27.
[21] CCA Alliance Comments, *loc. cit.,* pp. 38-39.
[22] LTPP Scoping Memo, *loc. cit.*, R.12-03-014, footnote 7, p. 6 and footnote 11, p. 12.

C. Overall Effects on CAM Procurement

Q. What is your assessment of the overall effects of SB 695 and SB 790 on Commission policies and practices regarding CAM procurement and associated cost allocation?

A. SB 695 and SB 790 are evidence that the Legislature intends for the Commission to ensure fair IOU cost recovery, but in a manner that does not unnecessarily impede or compromise the competitive retail choice market. It is not simply sufficient for the Commission to presume that each and every project they authorize the IOUs to undertake has some tangential link to system or local reliability that benefits all customers in their footprint, and therefore all customers must pay. Instead the Commission must impose a much more rigorous standard to ensure that any such authorization is <u>required</u> to ensure reliability and provides <u>real benefits</u> to <u>all</u> customers, especially to customers who would prefer to be served by a non-IOU supplier. Chapter IV of this testimony addresses proposed criteria by which the Commission would determine that an authorized IOU procurement met the requirements of P.U. Code Sections 365.1 (c) (2), 380 and 366.2 pursuant to SB 695 and 790 and a standard process the Commission would follow in making that determination. Chapter V addresses the "fair and equitable" cost allocation specified in P.U. Code Section 365.1 (c) (2), as required by SB 790.

Q. Has the Commission also determined that statutes permitting CAM procurement must be considered in the context of other provisions of the P.U. Code?

A. Yes. In D.11-05-005, the Commission considered some conflicting interpretations of SB 695 by parties regarding whether the Commission could require the IOUs to use an energy auction to establish the net capacity cost for the CAM. The Commission found that it is also obligated to comply with P.U. Code 380, which specified the objectives the

Commission must meet in establishing RA requirements for its jurisdictional LSEs:

> This interpretation is consistent with the Commission's responsibilities pursuant to Public Utilities Code Section 380(b) to achieve all of the following objectives in establishing resource adequacy 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." **Nothing in this statutory scheme or the legislative history of SB 695 supports the parties' contention that the Commission abdicates its authority** in favor of offering the utilities a menu of options for the utilities to determine the net capacity costs and benefits of system resources. **It is the Commission's duty**, not that of the utilities, to "equitably allocate the cost of generating capacity…" (emphasis added)[23]

As explained above, P.U. Code Section 380 (b) was originally established in AB 380 and, among other things, provided the guiding objectives used by the Commission in establishing and refining its RA program. Thus, in D.11-05-005, the Commission has already determined that its decisions involving CAM procurement must also meet the requirements of P.U. Code Section 380 (b).

Moreover, as discussed above, SB 790 provided a significant addition to these guiding objectives, as follows:

> Section 380 (b) (4): Maximize the ability of community choice aggregators to determine the generation resources used to serve their customers.

This significant and equally important objective provides additional guidance to the Commission that must be used in determining when the CAM should apply. Indeed, the Commission has a duty to ensure that any authorized CAM procurement does not violate this objective.

[23] D.11-05-005, pp. 13-14.

Q. Is the Commission's review of CAM confined to modifications made by SB 695 and SB 790?

A. No. The Commission previously recognized that it is necessary to conduct a full review of the CAM as implemented in D.06-07-029. Specifically, in D.10-06-018 (Track 2 RA Decision), the Commission promised to take a "comprehensive look" at the CAM, including identifying protocols by which retail choice LSEs could opt-out of responsibility for utility procurement.[24] Notably, this decision, which was approved nine months *after* passage of SB 695, committed to a broader review of the CAM, acknowledging that changes to the CAM involved more than SB 695 alone.[25]

IV. CRITERIA AND PROCESS TO DETERMINE WHEN CAM IS APPLICABLE

<u>Witness</u>: Sue Mara

A. Key Considerations

Q. What are the key considerations in determining when CAM procurement should be authorized?

A. Essentially, CAM procurement should be the exception, not the rule. Moreover, the Legislature has imposed guidelines the Commission must follow in imposing CAM charges on all customers. As noted above, CAM procurement must meet the conditions specified in P.U. Code Sections 365.1 (c) (2) (A), (B) and (C),[26] but also comply with the Commission objectives for the RA program set forth in P.U. Code Section 380 (b). In accordance with P.U. Code Section 366.2 (g), the Commission cannot authorize CAM payments unless the associated benefits of the CAM project have been fairly and

[24] D.10-06-018, pp. 73-74.
[25] See, for example, D.10-06-018, Conclusion of Law Number 5, p. 80.
[26] As amended by SB 790.

equitably allocated to CCA customers. In addition, as a condition precedent, the Commission must enforce the provisions of P.U. Code 454.5 that were established in AB 57[27] and set the requirements the IOUs must meet to serve their bundled customer load. Moreover, the Commission must consider and apply its long-standing policy regarding cost causation[28] to ensure that the CAM procurement and associated allocation of benefits are properly designed and implemented. Finally, the Commission must fulfill its commitment to "competition and customer choice."[29] This requires that the Commission make every effort to <u>minimize</u> CAM procurement, while continuing to ensure that reliability requirements are met.

1. Cost Causation Principles

Q. You have discussed the referenced P.U. Code sections in some detail above, but please explain how cost causation principles apply to CAM procurement?

A. Using the principle of cost causation, the customers causing the particular need for the resource should pay for it. If the load of the bundled utility customers is driving the peak or decreasing the system load factor, then bundled customers should pay for the resources necessary to meet that need. In determining whether to apply CAM, the Commission should only do so when the need creating the costs can be attributed to *all* customers.

A recent Decision in the current RA proceeding, R.11-10-023, made a similar determination regarding cost causation and IOU bundled load in determining that revisions were required to the factor used in assigning RA requirements to LSEs. The

[27] Stats 2002, Ch 835.

[28] In its newly-approved OIR (R.12-06-013) to examine the IOUs' residential rate structure, the Commission stated that "[d]eveloping equitable rates based on the principle of cost causation is one of the underlying goals of the Commission's ratemaking process." (p. 13, from Draft OIR, issued June 11, 2012)

[29] See, for example, D.06-07-029, p2, Conclusion of Law No. 11, p. 61; D.11-12-018, p. 4. Conclusion of Law No. 2, p. 108.

Decision[30] acknowledged that the existing method, which uses a single, system average factor, did not appropriately reflect the "peakiness" of the loads served by each LSE.[31] The Decision cited D.11-06-022, which found that the current method represented a cross subsidy from industrial and commercial customers, which are primarily the customers of the ESPs, to residential customers, which are primarily the customers of the IOUs.[32] The Decision concludes that the proposed revisions should be adopted, in part, because they would "improve cost allocation related to cost causation."[33] Thus, the Commission recognized the connection between the load characteristics, such as "peakiness," and proper cost allocation to comply with cost causation principles. CAM procurement requires the same type of analysis and consideration.

Q. Has the Commission identified other cases of potential cross subsidy that must be considered in this proceeding?

A. Yes. The Commission identified another, but similar, cross subsidy in the 2006 LTPP proceeding. In D.07-12-052, the Commission found that differences in load characteristics between the IOUs and the ESPs may lead to cross subsidies and committed to address its concerns.[34] The issue originated in AReM's testimony in R.06-02-013, in which I testified that cost allocation of any "system resources" must be linked to cost causation.[35] In D.07-12-052, the Commission cited directly from AReM's testimony that "[i]f bundled customers' load is exacerbating the peak or decreasing the load factor (as SCE suggested), then the bundled customers should pay for the resources

[30] The proposed Phase 1 RA decision was approved at the Commission's June 21, 2012 meeting, but the final decision had not been released at the time this testimony was finalized.
[31] Proposed Decision, Phase 1 RA, R.11-10-023, issued May 22, 2012, p. 24.
[32] PD, RA Phase 1, *loc. cit.*, pp. 24-25.
[33] PD, RA Phase 1, *loc. cit.*, p. 27.
[34] D.07-12-052, December 20, 2007, pp. 117-119.
[35] D.07-12-052, p. 117.

necessary to meet that need."[36] At the same time, the Commission noted the "absence of a standard methodology or consistent practices for identifying system versus bundled resource needs" and the possible adverse effects that could result.[37] Moreover, the Commission expressed concern that CAM treatment for new resources might be used "inappropriately" when the resources were actually needed to meet bundled load.[38]

More recently, the OIR for the 2008 LTPP included within scope distinguishing load growth rates of bundled versus direct access load, stating: "In other words, energy service provider (ESP) load may grow at a different rate than bundled load and **there should not be a cross-subsidy between the two**" (emphasis added).[39] However, as explained in the OIR for the 2010 LTPP proceeding, "[n]o activity was taken on Phase II" in R.08-02-007.[40] Thus, the Commission has previously determined that a valid issue to consider in allocating CAM procurement is whether "bundled customers' load is exacerbating the peak or decreasing the load factor."

Specifically, the Commission must evaluate the characteristics of the load served by the utilities versus the characteristics of the load served by the ESPs and CCAs to determine the different rates at which they grow. The results of that analysis will determine cost causation for new generation and, therefore, provide the foundation needed for a rational and non-discriminatory allocation of those costs.

Q. Why is the potential for cross subsidies important to consider when determining whether to authorize CAM procurement?

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[36] *Ibid.*
[37] D.07-12-052, pp. 117-119.
[38] D.07-12-052, p. 118.
[39] OIR, R.08-02-007, February 14, 2008, Attachment A, Preliminary Scoping Memo, p. A-27.
[40] OIR, R.10-05-006, May 10, 2010, p. 7.

A. Without Commission consideration and action to eliminate cross subsidies, the IOUs will continue to plan and build for load that they do not serve, thereby burdening the competitive market with undesirable and unwarranted non-bypassable charges. Moreover, failing to analyze the characteristics of the migrated load (both direct access and CCA) versus the characteristics of bundled utility load means that the Commission is unable to allocate costs to "benefiting customers" in accordance with cost causation principles. In addition, in D.11-05-005, the Commission recognized the need to distinguish bundled load from system load to ensure proper cost allocation and committed to develop applicable "policies and processes," when conducting its further review of CAM procurement.[41] This is the proceeding in which that assessment is to occur.

2. IOU Obligation to Procure Under AB 57

Q. How does P.U. Code Section 454.5 apply to CAM procurement?

A. AB 57 was enacted in 2002 and set forth the requirements the IOUs must meet to serve their bundled utility customers. Under the AB 57 paradigm, the IOUs seek and receive up-front approval of their procurement plans and are generally assured of full cost recovery of any supply procurement made in compliance with those plans. However, the Commission has not enforced the provisions of AB 57 that require the IOUs to meet their bundled load and load growth over the long-term. Instead, the Commission's decisions beginning with D.06-07-029 and thereafter have required that most if not all IOU procurement of new generating resources are subject to CAM procurement without considering whether such resources are, in fact, needed to meet bundled load, without

[41] D.11-05-005, p. 16.

considering bundled load growth and without considering whether all customers truly benefit from the procurement..

Q. Which specific provisions of P.U. Code Section 454.5 are applicable?

A. P.U. Code Section 454.5 is lengthy, but the pertinent language is as follows (emphasis added):

> 454.5 (a) The commission shall specify the allocation of electricity, including quantity, characteristics, and duration of electricity delivery, that the Department of Water Resources shall provide under its power purchase agreements to the customers of each electrical corporation, which shall be reflected in the electrical corporation's proposed procurement plan. Each electrical corporation shall file a proposed procurement plan with the commission not later than 60 days after the commission specifies the allocation of electricity. **The proposed procurement plan shall specify the date that the electrical corporation intends to resume procurement of electricity for its retail customers, <u>consistent with its obligation to serve</u>.** After the commission's adoption of a procurement plan, the commission shall allow not less than 60 days before the electrical corporation resumes procurement pursuant to this section.
>
> (b) An electrical corporation's proposed procurement plan shall include, but not be limited to, **all of the following**:
>
> …
>
> (9) A showing that the procurement plan will achieve the following:
> (A) The electrical corporation, in order to fulfill its **unmet resource needs**, shall procure resources from eligible renewable energy resources in an amount sufficient to meet its procurement requirements pursuant to the California Renewables Portfolio Standard Program (Article 16 (commencing with Section 399.11) of Chapter 2.3).
> (B) The electrical corporation **shall create or maintain a diversified procurement portfolio consisting of both short-term and long-term electricity and electricity-related and demand reduction products.**
> (C) The electrical corporation **shall first meet its unmet resource needs** through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible.

Q. How should the Commission apply this code section in the context of its continuing commitment to a competitive retail market?

The Commission continues to indicate a commitment to the competitive retail market and ensuring that its policies and practices do not undermine that market.[42] Further, the Commission continues to take seriously and thoughtfully apply cost causation principles to avoid cross subsidies, as discussed above. Taken in that context, this code section requires that the IOUs fulfill the following obligations:

1. The IOUs are required to identify their "unmet needs" in serving their bundled utility load over the "long term."
2. Identification of "unmet needs" requires the IOUs to project expected load growth as well as the characteristics of that load, such as changes to load factor (*i.e.,* "peakiness") over time.
3. Identification of "unmet needs" requires the IOUs to include in such "unmet needs" the megawatts associated with (a) power contracts that currently serve bundled customer load and are terminating during the long-term planning period and (b) power plants that currently serve bundled customer load and are projected to retire or otherwise be unavailable during part or all of the long-term planning period.
4. The IOUs' procurement plans must identify the specific resources or resource types the IOUs will procure or build to meet <u>100%</u> of the identified "unmet needs."
5. The IOUs' "unmet needs" can be met by existing or <u>new</u> generation resources, with a priority given to demand response and energy efficiency.
6. The IOUs' procurement plans must specify both existing and <u>new</u> resources sufficient to meet 100% of the identified "unmet needs" over time.

[42] See, for example, D.10-06-018, pp. 37 and 38.

In addition, the Commission must enforce these IOU obligations, when reviewing and acting on the IOUs' AB 57 procurement plans. Establishing accurate and compliant Bundled Procurement Plans is a condition precedent for the Commission to determine when CAM procurement may be necessary.

Q. Please explain.

A. The Commission has a statutory obligation first to "ensure" that CAM procurement is needed to meet a specified reliability need pursuant to P.U. Code Section 365.1 (c) (2) (B). Obviously, the "need" must be incremental to "needs" already associated with a particular LSE. If the "need" is actually an "unmet need" of the IOUs' bundled customers, the conditions for CAM procurement required by statute have not been met and the CAM procurement cannot be authorized. This is true even if the proposed procurement would meet a "reliability need" as defined by statute.

Q. So not all "reliability needs" meet the conditions of the relevant P.U. Code Sections?

A. No. Any new resource, be it a generating unit or demand response or energy efficiency, meets "reliability needs." As a consequence, the <u>existence</u> of that new resource <u>alone</u> is an insufficient measure to determine whether CAM procurement can be authorized. ESPs and CCAs installing or contracting for any new resource meet a reliability need, but do not expect nor believe they are entitled to CAM payments. The protections for CCAs added by SB 790 now make clear that LSEs meet their own load and RA requirements and that any CAM procurement must be incremental to and separable from any one LSE's unmet load requirements.

Q. Please provide an example.

Applying this approach, if an IOU had a contract with a 500-megawatt ("MW") steam plant, which was used primarily to serve bundled load and planned to retire or shut down within 5 years, the IOU would be required to include that 500 MW in its "unmet needs" as part of its AB 57 Bundled Procurement Plan. If the IOU later filed for Commission approval for CAM procurement to replace the 500-MW unit, the Commission would be required to reject the application. This Commission action is justified, even though a replacement unit is "needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory."[43]

Specifically, the P.U. Code requires first that the IOUs' bundled customers' "unmet need" be met before any CAM procurement is considered or authorized. As indicated, the IOU's proposed replacement unit is, in fact, needed to meet its bundled customer load. While incidental reliability "benefits" would likely accrue to "all" customers, bundled customers would benefit disproportionately more, because the customers of other LSEs would subsidize their "unmet needs." At a minimum, authorizing CAM procurement for such replacement units would seem to run afoul of P.U. Code Sections 366.2 (a) (4) and 366.3 (g), which prohibit cost shifting and paying for benefits not received relative to CCAs.

Taking real-world examples, the Commission must enforce P.U. Code Section 454.5 and require the IOUs to procure to <u>replace</u> any unmet needs created by the closing of Once-Through Cooling ("OTC") units used to serve bundled load. While true that closing these plants impairs reliability and replacing them "meets a reliability need," P.U. Code

[43] PU Code, §365.1(c)(2)(A).

Section 454.5 must first be satisfied. IOU's unmet needs do not qualify for CAM treatment and should not be authorized as such.

B. Benefits Test

Q. The Commission referred to the potential need for a "Benefits Test" to determine when to authorize CAM procurement in D.11-05-005. Please explain your views on this.

A. As mentioned above, the Commission has previously determined that it would consider a "test of 'who benefits' under SB 695, and if so, the construction of such a test."[44] The relevant P.U. Code requires that the Commission make a determination that the designated procurement meets a specified system or local reliability need and "*benefits all customers*" in a utility's service area before the Commission may authorize a utility to employ the CAM.[45] As noted above, this limits the application of the CAM. For example, the CAM would not apply to procurement needed to meet the future needs of an IOU's bundled customers pursuant to P.U. Code Section 454.5. In addition, the CAM would not apply if the procurement is designed to meet specific <u>local</u> needs that do not benefit "<u>all customers</u>" in the IOU's service territory. Accordingly, any "benefits test" must account for these limitations. However, a "benefits test" alone may be too restrictive to meet the requirements of the applicable P.U. Code Sections. Instead, I am proposing criteria for the Commission to apply in determining whether to authorize a particular CAM procurement.

[44] D.11-05-005, p. 16.
[45] PU Code, §365.1(c)(2)(A).

C. Proposed Criteria

Q. What criteria do you propose?

A. After reviewing the pertinent P.U. Code Sections, Commission policy decisions, and Commission practices, I propose six criteria. These criteria achieve the twin goals of meeting statutory requirements and enabling retail choice. The Commission must determine that each criterion has been met before it can authorize a particular CAM procurement. I also recommend a process for the Commission to follow in making the CAM determination, which is discussed in the next section.

The proposed criteria are:

1. The IOU's Application requests, as required by P.U. Code Section 365.1 (c) (2) (A): (i) approval for a specific contract with a third party to procure generation resources; or (ii) an order to procure a specific UOG resource.
2. The Commission has previously determined that the MWs identified in the Application may be subject to CAM procurement.[46]
3. The Commission determines that the project identified in the Application fulfill an unmet need that is not attributable to any individual LSE.
4. The Commission determines that the project identified in the Application is required by the CAISO to meet a specific System or Local RA need that cannot be reasonably met by other existing resources, demand response, energy efficiency or other alternatives and is required to be operational as of the timeline proposed in the IOU's Application to avoid degrading grid reliability.

[46] This step is addressed in the proposed CAM approval process discussed in the next section.

5. The Commission determines that the project identified in the Application benefits all customers within the IOU's service territory, including DA and CCA customers, by the way in which it meets the reliability needs specified by the CAISO, as required by P.U. Code Section 365.1 (c) (2) (B).

6. Local RA projects in an IOU's Local RA Area provide comparable reliability benefits, as specified by the CAISO, to all customers located in the entire IOU's service area, as required by P.U. Code Sections 365.1 (c) (2) (A), 365.1 (c) (2) (B), and 366.2 (g). Projects that provide the specified reliability benefits primarily to customers located within the Local RA Area where the project will be developed must be rejected as inconsistent with the P.U. Code Sections noted.

Q. How would the Commission determine that the IOU's Application has met the criteria?

A. This is essentially a "check list" to be reviewed and assessed by the Commission for each CAM application submitted by the IOUs. The Commission would assess each criterion and determine if it has been met though consideration of the IOU's Application and accompanying testimony, evidence provided by parties, and the outcome of hearings if necessary. If the Commission's answer to each is "yes," then the Commission may authorize the CAM procurement. If any of the criteria is not met (*i.e.*, a "no" answer), the Commission must reject CAM as the applicable cost allocation treatment for the Application.

Q. Your criteria do not specifically address cost causation. How is that concept incorporated?

A. Cost causation principles are best addressed upfront at the time when the Commission identifies the megawatts that may be subject to CAM procurement. This step takes place in the LTPP proceeding when the Commission determines the unmet need for the overall system, if any, and the procurement needs of IOUs to comply with P.U. Code Section 454.5 and cost causation principles, as well as the planning horizon for any procurement required. I discuss that process in the next section.

D. Proposed Process

Q. What process do you propose the Commission to follow in determining whether a particular CAM project should be approved?

A. I envision a two-stage process. In the first stage, the Commission would be required to establish the megawatts of unmet need that cannot be attributed to any specific LSE. A critical component of this first stage will be the Commission's consideration and identification of the procurement requirements to meet the bundled load obligations of the IOUs pursuant to P.U. Code Section 454.5 and cost causation principles, which would not be subject to CAM procurement. As discussed above, this step would require a full evaluation and assessment by the Commission of the load obligation attributable to each IOU, including its projected load growth and peak characteristics during the planning period. The IOU's bundled load obligation would be taken off the top of the overall system need. In addition, the CAISO must be involved to define the specific System or Local RA reliability needs and operational characteristics, if any, and the time frame by which they must be satisfied. After completing this assessment, the Commission would issue a decision identifying the megawatt amount of the unmet need, which is potentially subject to CAM procurement, and the time frame in which the need occurs. In the decision, the Commission would also direct the IOUs, as applicable, to pursue CAM procurement activities. The issuance of that decision would trigger the option for ESPs and CCAs to pursue LSE Opt-Out, which is discussed in Chapter VI of this testimony.

In the second stage, the IOUs would submit a CAM application for a particular project or PPA and the Commission would conduct the assessment required by the criteria proposed above. The IOUs will be obligated to provide evidence to validate the proposed criteria. The application process may require hearings and must include the active involvement of the CAISO. The CAISO would be required to provide evidence to demonstrate that the project identified in the IOU's Application: (i) meets the reliability need the CAISO had previously defined (in stage one of the proposed process); and (2) and cannot be reasonably met by any other existing or new resource, including demand response and energy efficiency. If the Application meets each criterion, the Commission will approve it.

Q. Please provide more details on the how the Commission would establish the megawatts that may be subject to CAM procurement in the first stage.

A. For the Commission to establish the MWs of unmet need that cannot be attributed to any specific LSE, it must first ensure that the IOUs have met their obligation to serve their bundled load, including their long-term procurement obligations pursuant to P.U. Code Section 454.5. I have discussed the IOUs' bundled procurement requirements in some detail above. In addition, to address proper cost causation, the Commission must assess to what extent the IOUs' load growth is driving the need for new generation. If the need for new generation is attributed primarily to IOU load, such as residential load growth in the central valley, as has been previously indicated,[47] then the "need" to procure such new generation resources belongs to the IOUs and cannot be allocated to "all customers." Moreover, the IOUs should be prohibited from including existing and reasonably expected future DA and CCA load in their load and load growth assumptions. If they are not serving the load, they should not be procuring to meet it. These issues and ultimate Commission decisions would all be addressed in the first stage.

Q. Is this the same process currently followed by the Commission?

A. No. The LTPP "process" has been somewhat haphazard since it began in 2004. For example, this current LTPP proceeding is first addressing Local needs, but only in Southern California.[48] The current approach leads to inefficient decisions and creates the potential for CAM procurement that may not be compliant with overarching Commission policy and statutory requirements. To remedy this current situation, I recommend that the Commission adopt the proposed process outlined above, which affords an equitable and deliberate approach for establishing CAM procurement, minimizes its use, and ensures compliance with the applicable statutory requirements. I recommend that the Commission adopt this process beginning in 2013 with consideration of the IOUs' Bundled Procurement Plans, which are scheduled to be filed in March 2013.[49]

V. MODIFICATIONS TO THE CAM CHARGE

Witness: Mark Fulmer

Q: What is the purpose of this section?

[47] D.07-12-052, p. 117.
[48] LTPP Scoping Memo, R.12-03-014, May 17, 2012, item no. 1, p. 5.
[49] LTPP Scoping Memo, R.12-03-014, May 17, 2012, p. 13.

A: This section addresses the issues numbered 8 and 9 in the May 17, 2012 Scoping Memo in Track 1 of this proceeding:

> 8. How the costs of any additional local reliability needs should be allocated among LSEs in light of the Commission's adopted cost allocation mechanism (CAM) per Senate Bill (SB) 695, SB 790, D.11-05-005 and any relevant previous decisions;
>
> 9. Whether the CAM should be modified at this time.

A. Background

Q: How have past Commission decisions addressed the calculation of net capacity costs for PPAs with new generating assets?

A: Allocation of net capacity costs and benefits to "benefiting customers" was first approved in D.06-07-029. In this Decision the Commission determined that benefiting customers would pay for the net cost of capacity defined as "a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract."[50] The Commission found that "the energy and capacity from any new resources should be unbundled, with the costs and benefits of the RA capacity component socialized to all customers connected to the utility's distribution system, and the costs and benefits of the energy component assigned to those that value the energy the most, as demonstrated through an auction or similar mechanism."[51]

The CAM was further defined in a settlement adopted by the Commission in D.07-09-044. This settlement outlined principles for the energy auction, including a detailed description of the pre-bid and bid process, a description of the products to be included in

[50] D.06-07-029, p. 26.
[51] D.06-07-029, p. 31.

the auction and the bid evaluation processes.[52] In the event that an auction failed to produce a successful bid for the energy products, the settlement agreement indicated that capacity costs be calculated via a mechanism defined in the Joint Parties' Proposal.[53]

Q: What is the methodology for calculating net capacity costs as outlined in the Joint Parties' Proposal?

A: The Joint Parties' Proposal calculates net capacity costs on a proxy basis by imputing energy costs and revenues retroactively based on day-ahead market prices.[54] The revenues included in the Joint Parties' Proposal are imputed based on day-ahead pricing for the hours in which is it determined that the plant would have been economic to dispatch.[55] Revenues associated with ancillary services are included but are limited to non-spinning reserves and are only examined for hours in which it was determined that the plant would not have been economic to schedule in the day-ahead energy market.[56]

Q: Have any PPAs been subject to CAM allocation following the adoption of D.07-09-044?

A: Yes, several PPAs have been subject to CAM allocation through both the energy auction and a proxy calculation similar to the Joint Parties' proposal. Southern California Edison (SCE) has conducted an energy auction for its Long Beach and Blythe generation projects.[57]

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[52] D.07-09-044, pp. 7-8.
[53] D.07-09-044, Appendix A, p. 23.
[54] D.07-09-044, Appendix A, p, 23.
[55] D.07-09-044, Appendix A, p. 25.
[56] D.07-09-044, Appendix A, p. 23.
[57] *Reply Comments of Southern California Edison Regarding the Implementation of SB 695*, R.10-05-006, October 8, 2010, p. 7.

In D.10-07-045, the Commission approved CAM allocation for Pacific Gas and Electric Company's (PG&E's) Marsh Landing and Contra Costa generation projects using a method analogous to the method outlined in the Joint Parties' Proposal.[58] It has also been authorized for CHP projects.

Q: What does the P.U. Code say concerning the calculation of net capacity costs for the CAM rate?

A: As set by SB 695, Section 365.1(c) (2) (C) of the P.U. Code is consistent with the method laid out in D.06-07-029 and D.07-09-044, with the exception that it includes utility-owned generation:

> Net capacity costs shall be determined by subtracting the energy and ancillary services value of the resource from the total costs paid by the electrical corporation pursuant to a contract with a third party or the annual revenue requirement for the resource if the electrical corporation directly owns the resource.

Q: Do you have any fundamental concerns with how the method laid out in the statute is being implemented?

A: Yes. The current method, particularly the Joint Parties' proxy calculation, does not properly value system or local capacity because it relies on the short-term value of energy to produce an imputed capacity value from a long-term contract price. By design, the imputed capacity value will be inversely related to energy price. When examined in the short term, this can create results that are fundamentally problematic and do not accurately reflect the value of RA capacity. The value of capacity should reflect the overall need for capacity in the location in which it is needed or for the system when the resource is not in a specific load pocket. In the event that limited capacity is available

[58] D.10-07-045, Appendix A.

capacity value should increase and in the event that there is excess capacity available, the value should decrease. This would not be the case under the current CAM methodology.

Consider for example what would happen during a good hydro year in the Pacific Northwest. While the availability of this hydroelectric generation would have no material impact on RA needed in Southern California, it would likely impact the imputed capacity value under the current CAM. Cheap hydroelectric generation would depress market prices throughout the State. Energy valued for the CAM through the proxy calculation would be assigned a relatively low price, creating a high imputed value for capacity. Conversely, in the event of drought and/or gas delivery issues, it can be expected that energy prices would increase. However, under the CAM, the imputed value of capacity would decrease.

Both of these examples illustrate the disconnect between the CAM methodology for imputing capacity values and the true long-term value of capacity at a given time. In reality, the capacity value would not be subject to the dramatic swings seen in the short-term energy market, but would tend to move in tandem with energy prices, falling during times in which alternative capacity is available and rising during times of gas supply disruption, drought, or extreme weather events.

B. Changes to the CAM Calculation for PPAs

Q: Should the CAM be modified at this time?

A: Yes. AReM/DACC/MEA propose several changes to the CAM, including changes to the energy auction terms and changes to the proxy calculation outlined in the Joint Parties' Proposal.

Q: How should the energy auction terms approved in D.07-09-044 be modified?

A: D.07-09-044 requires that the back-to-back toll product available for auction be limited to a term not to exceed five years.[59] This provision should be modified to restrict the auction products to a minimum of five-years, not a maximum. Longer term tolling products would more accurately reflect the incremental hedging value of the PPA.

Q: How should the Joint Parties' Proposal be modified?

A: The Joint Parties' Proposal should be modified to ensure that the full value of energy and other products is netted from the contract price. This includes full accounting for the value of all potential ancillary services the plant could provide, flexible capacity attributes, renewable integration costs and the options value associated with a long-term tolling contract. In particular, the calculation of the value of products and services that the plant may provide must include expected revenues from all applicable ancillary services products in CAISO markets, the imputed value derived from the use of the plant for self-provision of ancillary services by the IOU (if applicable and then at the value of the CAISO products), and the revenues expected from any additional products that become available. For example, the CAISO is currently developing a flexible ramping product to assist with integration of renewables, which is currently scheduled for Board approval in September.[60] The CAISO has also developed a black start and system restoration service to be approved at the July 2012 Board meeting. A plant able to provide this service will meet CAISO requirements but be paid by the transmission owners for the service.[61] This

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[59] D.07-09-044, Appendix A, p. 5.
[60] http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx
[61] http://www.caiso.com/informed/Pages/StakeholderProcesses/Blackstart_SystemRestoration.aspx

is another source of potential revenue to the plant that should be netted out of the costs to be recovered through the CAM payments.

Q: Does the Joint Parties' Proposal account for any other ancillary services in addition to non-spinning reserves?

A: No. The Joint Parties' Proposal does not include any ancillary services except for the cheapest one, non-spinning reserves. In addition to non-spinning reserves, the CAISO has an operating day-ahead and real-time market for regulation up, regulation down, and spinning reserves. The Joint Parties' proposal excludes these and other ancillary service products.

Q: How large is the market for these additional ancillary service products?

A: According to the CAISO's 2011 Annual Report, the 2011 average hourly regulation up and regulation down requirements were roughly 350 MW and the average hourly spin and non-spin requirements were roughly 850 MW.[62] The average prices for each of these products in the day-ahead and real-time markets are shown in Table 1 below.

Table 1: Average Ancillary Service Prices, 2011 ($/MW) [63]

Product	Day-Ahead Market	Real-Time Market
Regulation Up	$10.84	$9.17
Regulation Down	$6.97	$3.78
Spinning Reserve	$9.15	$5.09
Non-Spinning Reserve	$1.06	$0.45

[62] California Independent System Operator. 2011 Annual Report on Market Issues and Performance. April 2012, p. 97.

[63] California Independent System Operator. 2011 Annual Report on Market Issues and Performance. April 2012, p. 98.

Q: Is it reasonable for the proxy calculation outlined in the Joint Parties' Proposal to include only non-spinning reserve?

A: No. The proxy calculation outlined in the Joint Parties' Proposal should be modified to include all major ancillary service products that are currently available in the CAISO market. As other products become available, the calculation should be modified to incorporate the expected revenues from those products, too. As shown in Table 1 above, non-spinning reserve is the least-cost ancillary service. To the extent that a generator is able to bid into the ancillary services market, the plant owner/operator will seek to maximize profits and to that end will potentially bid to provide energy or ancillary services based on the generators expected costs and operating constraints. Inclusion of all the available ancillary services products that a unit is capable of providing creates a more accurate assessment of revenues available to the generator, and therefore a more accurate assessment of the net capacity costs.

Q: How should all the ancillary services be accounted for in the proxy calculation?

A: The Joint Parties' Proposal only looks to potential ancillary service revenue during hours in which it finds the plant would have been uneconomic to schedule in the day-ahead energy market.[64] In contrast, AReM/DACC/MEA recommend that the proxy calculation consider all possible revenue streams (energy, non-spinning reserve, regulation, etc.) simultaneously.

Looking at day-ahead prices for energy and ancillary services, PPA revenues should be estimated by assuming the resource was dispatched to provide energy and/or ancillary

[64] D.07-09-044, Appendix A, p. 25.

services to maximize profit subject to operational constraints. For example, if a resource can provide regulation and regulation is more valuable than energy, it would be assumed that the resource would bid into the day-ahead regulation market, rather than the energy market.

According to the CAISO, only 1% of ancillary service procurement takes place in the real-time market, with the remainder procured on the day-ahead market.[65] For simplicity AReM/DACC/MEA recommend that the proxy calculation be limited to the CAISO day-ahead market.

Q: Does the Joint Parties' Proposal account for renewable integration costs?

A: No.

Q: Do you have a proposal for how renewable integration costs might be included in the proxy calculation?

A: Inclusion of all four currently-traded ancillary services, as described above, would help to include renewable integration costs in the calculation. In addition, as discussed above, when additional products become available and can be assigned value, it is important that the proxy calculation be modified to incorporate the value of these integration products. In this regard, it is important to note that the CAISO is considering the development of just such services in its stakeholder processes now.[66]

Q: How does the Joint Parties' Proposal account for the options value associated with a long-term tolling contract?

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[65] California Independent System Operator. 2011 Annual Report on Market Issues and Performance. April 2012, p. 99.

[66] E.g., http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

A: The Joint Parties' Proposal does not explicitly account for the options value associated with a long-term tolling contract.

Q: Do you have a proposal for how the options value might be included in the proxy calculation?

A: Quantification of the options value is a complex endeavor. According to D.06-07-029, contracts must be for a minimum of five years to be eligible for CAM treatment.[67] Under the Joint Parties' Proposal for the proxy calculation, including the proposed modifications described above, the value for capacity would be a function of day-ahead market prices.

By calculating a value for long-term capacity that is a function of short-term prices, the current CAM method ignores one of the primary drivers of long-term PPA cost: the opportunity value of purchasing energy with agreed-upon terms in a market characterized by energy price volatility. This option value is important for energy purchasers and should be accounted for as a value netted against the PPA cost. It is noteworthy that the energy auction was designed in part to do that, by allowing parties to bid to have the rights to the energy output of the units for a multi-year period. Just because the auction mechanism is no longer required, that is no reason to ignore the fact that there is value – option value – embedded in the contract by virtue of its term, and that value should be included in the CAM calculation. AReM/DACC/MEA recommends that the Commission convene a workshop of interested parties for the purpose of determining an appropriate adder for this purpose.

[67] D.06-07-029, p. 28.

C. Changes to the CAM Calculation for Utility-Owned Generation

Q: The sections to the P.U. Code added by SB 695 say that net capacity costs can, upon approval by the CPUC, be calculated for utility-owned generation, with benefits and costs spread to all benefiting customers. What issues does this raise?

A: The same fundamental concerns I mention in the prior section concerning the net capacity cost allocation scheme for PPA resources are equally valid for UOG resources. This is because these concerns are about the valuation of the energy, ancillary services, and other products provided by the plant and not the PPA itself.

Q: Are there any other unique issues with the calculation implied in SB 695?

A: Yes. The statute says to determine net capacity costs "by subtracting the energy and ancillary services value of the resource from the total costs paid by the electrical corporation pursuant to a contract with a third party or the annual revenue requirement for the resource if the electrical corporation directly owns the resource."[68] In the Commission's interpretation of this provision it is important that the annual revenue requirement associated with UOG be analogous to the total costs paid by the electrical corporation associated with a PPA.

My biggest concern with using the annual revenue requirement is that the imputed capacity costs of a utility-owned generating asset changes over time as the plant is depreciated. In the early years of a UOG plant's life the revenue requirement associated with capital costs is higher, while in latter years it is lower. While this makes accounting sense, directly using this changing revenue requirement distorts the imputed <u>value</u> of the

[68] PU Code Section 365.1 (c) (2) (C)

plant's capacity as defined by the proxy calculation. A plant's depreciation schedule should not impact the value of the capacity it is providing.

For illustration purposes, I took the basic cost data for an advanced combined cycle plant from the 2009 CEC Comparative Costs of California Central Station Electricity Generation Final Staff Report.[69] The basic parameters are shown in Table 2 below.

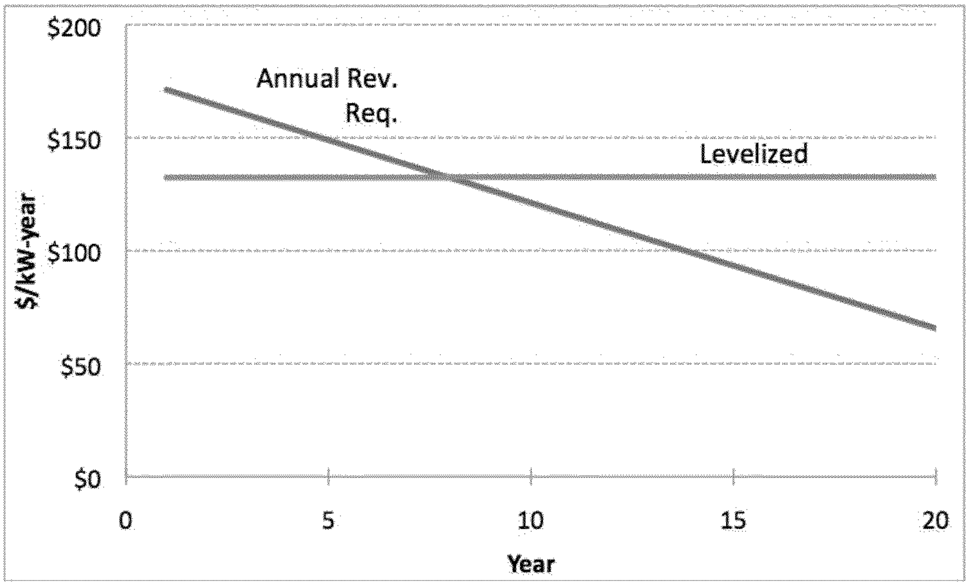
Table 2. Basic Parameters for UOG CAM Example

Plant Type	Advanced Natural Gas Combined Cycle
Investment, 2009$ / kW	$990
Cost of Capital	8.24%
Book Life	20
Net income tax rate	40.7%
Year 1 Fixed O&M (2009$/kW-year)	$7.17
Annual O&M escalation	2%

The fixed "capacity" cost of the facility—prior to the subtraction of a certain amount that would be covered by energy sales—for this example is shown in Figure 1. As the figure shows, the fixed costs would start at $171/kW-year in year 1 and decline to $121/kW-year in 10. The levelized fixed cost value is $132/kW-year, which is 23% less than the first-year value.

[69] Klein, Joel. 2009. Comparative Costs of California Central Station Electricity Generation Technologies, California Energy Commission, CEC-200-2009-017-SD. Cost of Capital from A12-04-015, p. 4.

Figure 1. Annual Fixed Cost and Levelized Revenue Requirement



Q: Are there any examples of this front-loading of capital costs in the revenue requirement in recent applications?

A: Yes. The testimony supporting PG&E's application for approval of the amended Oakley purchase and sale agreement provides the projected capital and fixed cost revenue requirement for the first eight years of operation.[70] The data presented there shows 38% decline in the capital and fixed cost revenue requirement from year 1 to year 8.

Q: Given this problem, what do you recommend?

A: I see no reason that the reference in SB 695 to the annual revenue requirement cannot be interpreted to allow for an annual levelized revenue requirement, rather than the actual yearly revenue requirement collected by the utility. This interpretation more closely resembles a tolling contract and avoids potential issues associated with depreciation.

[70] Pacific Gas and Electric Company, The Oakley Project Prepared Testimony, A.12-03-026, May 21, 2012, Table 6-1, p. 6-1.

Q: Couldn't a PPA contract be front-loaded, too?

A: Yes, and if so, the same solution should be applied.

D. A Cap is Needed for the CAM

A: Your testimony so far points to the fact that the net capacity cost calculations coming out of D.06-07-029, D.07-09-044, D.11-05-005 and D.11-12-035 may be faulty and systematically result in higher than reasonable net capacity costs. You also made some recommendations on how to address the capacity overvaluations. (e.g., levelizing UOG revenue requirement, including all ancillary services that the units can supp and other products beyond non-spinning reserves). Do you have any additional recommendations so that CAM costs better reflect capacity values?

Q: Yes. The point of the CAM calculation is to attempt to value the RA portion of a resource that will be borne by all benefiting customers. Ideally, there would be an open and liquid market for local and system RA from which a fair value could be derived. But such a market does not exist. While there is the buying and selling of RA capacity among generators, brokers and LSEs in a bilateral market, it is not in an open exchange.

Q: Given this limitation, how can a CAM cap be set?

A: There are a number of ways a cap could be set, such as using secondary sources of RA market data or administrative values. I recommend that the Commission approve the concept of a CAM cap and order a workshop on how its value should be set.

Q: The P.U. Code section enacted by SB 695 says that the net capacity costs must be based on the PPA or utility revenue requirement minus the value of the energy and ancillary services provided by the resource. Why is it reasonable to have a cap?

A: First, introducing a cap does not change the fact that under what I would hope to be normal circumstances, the structure mandated in SB 695 would be used and result in a reasonable value. The cap does not replace or supercede the legislated method; it provides a backstop to ensure a reasonable result. This reasonableness in calculating CAM is precisely what is called for by the language in P.U. Code Section 365.1(b)(2)(B) that was added by SB 790:

> The commission shall allocate the costs of those generation resources to ratepayers in a manner ***that is fair and equitable to all customers***, whether they receive electric service from the electrical corporation, a community choice aggregator, or an electric service provider. (emphasis added)

Without the capping that I propose here, I believe that unfair and inequitable costs could be imposed on CCA and DA customers. And, as long as the resulting imputed price is reasonable and below the cap, the implementation method laid out in SB 695 is maintained.

Remember the CAM charge is not in place to collect stranded costs from departing load; that is the purpose of the Power Charge Indifference Amount ("PCIA"). The CAM is in place to allocate the costs of a product to all consumers of that product. All customers, no matter when they left IOU bundled service, must pay this charge. Without the protection of a reasonable cap or some other mechanism to guard against improper stranded cost recovery, there is no guarantee that the CAM would not effectively be another stranded costs charge.

E. Miscellaneous CAM Rate and Benefit Allocation Issues

Q: How are the CAM costs allocated?

A: Per D.06-07-027,

> All RA counting benefits and net costs are spread to the LSEs whose customers are allocated costs based on share of 12-month coincident peak, adjusted on a monthly basis to facilitate load migration. The contract costs paid and RA benefits received by DA (or CCA and muni load) and bundled customers should be based on a share basis equal to the credit share received. (page 31)

Q: Is this a reasonable?

A: Yes. It is reasonable that costs be allocated based on peak demands and it is imperative that the customers of each LSE receive RA credit proportional to the amount of CAM rate paid. Therefore, AReM/DACC/MEA do not recommend any changes in this regard.

Q: SB 695 states that the CAM rate treatment should apply to the full length of the PPA or life of the UOG asset. Given the volatility of the wholesale power market and increasing value of ancillary services and other products for renewable integration, is it possible that the sum of the imputed net revenues from the energy, ancillary service and other products from a plant could exceed the fixed cost of the contract or fixed UOG revenue requirement?

A: I suspect that it is possible, and if this were to occur, net capacity costs under the CAM treatment for that facility would be negative.

Q: How should a negative CAM charge be treated?

A: Because all customers are paying for the capacity of a CAM asset or PPA, and since all customers are receiving RA credit for that asset or PPA, then it follows that all customers should receive the residual revenues from a negative CAM charge. In practice, a negative CAM charge should receive the same treatment as a positive one: allocated using 12-month coincident peak allocators. This negative amount could offset on the customers' bills any positive CAM charges from other contracts.

In the event of a negative CAM charge, for example, the RA capacity credit for the contract or UOG resource should still be allocated among LSEs in the same manner that it would be if the CAM charge were positive.

VI. LSE OPT-OUT

A. Proposal for LSE Opt-Out

Witness: Sue Mara

1. Introduction, Background and Rationale

Q. Please explain the concept of an LSE Opt-Out.

A. The term "LSE Opt-Out" refers to the ability of an LSE, on behalf of its customers, to opt out of a CAM procurement and the associated charges imposed though the IOUs. Said another way, that LSE's customers would be exempt from CAM charges to the extent that LSE received Commission approval to opt-out of the CAM. Moreover, LSE Opt-Out provides incentives to ESPs and CCAs to procure multi-year RA capacity for their customers thereby reducing the need for CAM procurement by the IOUs in the first instance.

Q. Has the Commission previously considered adopting an LSE Opt-Out?

A. Yes. The issue was within scope in the RA proceeding, R.05-12-013, but never resolved.[71] For background, one party introduced the concept of an LSE Opt-Out at the time the Commission considered a non-bypassable charge for procurement of generation

[71] *Assigned Commissioner's Ruling and Scoping Memo for Phase 2*, R.05-12-013, December 22, 2006, p. 17.

reserves in R.01-10-024.[72] AReM later endorsed the concept in its testimony in the 2006 LTPP proceeding, R.06-02-013,[73] as did several other parties to that proceeding.[74] AReM submitted a detailed proposal for LSE Opt-Out in the RA proceeding, R.05-12-013.[75] Several other parties also submitted proposals for LSE Opt-Out in that RA proceeding.

Q. What has the Commission said about LSE Opt-Out in previous decisions?

A. When the Commission approved the CAM in D.06-07-029, it noted that the concept of an LSE Opt-Out from the CAM was "appealing"[76] and stated support.[77] However, the Commission decided not to adopt the proposal at that time, because it had "no viable enforcement program or mechanism."[78] Instead, the Commission deferred the issue to Track 2 of the R.05-12-013 RA proceeding, noting that it would "determine at that time" whether the opt-out could apply to existing contracts as well as to new Request For Offers ("RFOs").[79] However, Track 2 of the proceeding was focused primarily on consideration of a centralized capacity market and the resulting decision included only limited discussion of LSE Opt-Out, finding that the record did not support adoption of any of the proposals.[80] The Commission deferred the issue to be resolved in an unspecified future proceeding."[81] Since that time, the Commission has not rendered any further opinions on LSE Opt-Out.

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[72] D.06-07-029, p. 8.
[73] *Testimony on Behalf of the Alliance for Retail Energy Markets*, R.06-02-013, March 2, 2007, p. 14.
[74] D.06-07-029, p. 35.
[75] *Proposals and Comments of the Alliance for Retail Energy Markets on Resource Adequacy Track 2 Issues*, R.05-12-013, March 30, 2007, pp. 7-14.
[76] D.06-07-029, p. 35.
[77] D.06-07-029, p. 5.
[78] D.06-07-029, p. 35.
[79] D.06-07-029, p. 35.
[80] D.10-06-018, p. 74.
[81] D.10-06-018, p. 75.

Q. Why should the Commission approve an LSE Opt-Out mechanism?

A. LSE Opt-Out is needed to mitigate the anti-competitive effects of the CAM. In D.06-07-029, the Commission repeated its goals for robust and competitive wholesale and retail markets in California,[82] but expressed concern that the CAM it was adopting might afford "too much price guarantee and risk protection for the IOUs" that could "undermine the development of a more competitive market."[83] But the anti-competitive effects are broader than the Commission noted in D.06-07-029.

All decisions to impose CAM have the same impact on CCAs, ESPs and their customers. CCAs and ESPs are required to meet Commission-imposed RA requirements identical to the IOUs and in accordance with P.U. Code Section 365.1 (c) (2). When CAM is imposed, the customers of the CCAs and ESPs must not only pay their LSE for RA capacity costs <u>but they must also pay</u> the Commission-imposed costs for RA capacity procured by the IOUs. This impairs direct access and CCA formation by limiting the options of ESPs and CCAs to control costs in their own portfolios or assemble an RA portfolio of their own design in order to meet the specific preferences of their customers.

Moreover, as the Commission has acknowledged, the IOUs have the enormous benefit of guaranteed cost recovery through rates.[84] By contrast, ESPs must recover their costs in the competitive market with customers who can easily switch to another LSE or return to bundled utility service. Likewise, CCAs must recover all their costs from a limited customer base, each of which can return to utility service with short notice.

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[82] D.06-07-029, pp. 3, 24, and 25.
[83] D.06-07-029, pp. 24-25.
[84] D.10-06-018, p. 67.

The LSE Opt-Out mechanism proposed herein seeks to counterbalance some of these anti-competitive effects by providing LSEs with a way to avoid the CAM charges for their customers and control their own RA portfolio resources and costs. Permitting LSEs to "opt-out" of the CAM will provide ESPs and CCAs with a tool to control their own portfolio costs in the current bilateral RA market and with enhanced incentives to invest in resources and multi-year contacts. In doing so, the proposal meets a primary goal of the Commission's RA program -- to encourage investment in generation capacity that can meet California's reliability requirements.[85] In short, the proposal provides market incentives to ESPs and CCAs to enter into multi-year contracts for RA capacity. The current CAM approach not only provides no such incentives, it makes it less likely that CCAs or ESPs would be able to justify such investments.

Q. Does the Commission have special obligations toward CCAs that require the adoption of LSE Opt-Out?

A. Yes. As discussed above, SB 790 added statutory provisions that the Commission must meet regarding CCAs. Specifically, the Commission is required to fulfill the objective to "maximize the ability of community choice aggregators to determine the generation resources used to serve their customers."[86] CAM procurement directly conflicts with this objective by putting a portion of the CCA's RA portfolio under IOU control. While SB 790 did provide for the possibility of CAM procurement,[87] it also ensured that CCAs are clearly responsible for their own generation procurement. LSE Opt-Out is therefore necessary to comply with SB 790.

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[85] D.10.06-018, p. 2.
[86] PU Code Sections 380 (b) (4) and 380 (h) (5).
[87] See, for example, PU Code 366.2 (a) (5).

2. Details of LSE Opt-Out Proposal

i. Overall Design

Q. What criteria should be used to assess an LSE opt-out proposal?

A. The Commission should approve an approach that maximizes the incentives for LSEs to opt-out of the CAM, thereby minimizing IOU procurement for non-bundled customers and increasing and diversifying the buyers for new generation resources in the wholesale market. ESPs and CCAs would have the opportunity to apply to the Commission and obtain approval to "opt-out" from a prospective CAM charge on behalf of their customers.

Q. What are the basic elements of your opt-out proposal?

A. To obtain Commission opt-out approval, an LSE would be required to make a showing that it has procured adequate generation resources for a 5-year period.

AReM/DACC/MEA propose three opt-out options, chosen at the election of the ESP or CCA: (1) Load-Ratio Share Opt-Out; (2) Load-Based Opt-Out; and (3) Customer-Based Opt-Out. Each option is discussed below. The Commission would conduct a process similar to the RA showing process to confirm the ESP or CCA, as applicable, has met the conditions for opt-out. The Commission could delegate this process and any required compliance filings to Energy Division staff, as it does for the RA showings. This opt-out mechanism would apply to CAM charges imposed pursuant to D.06-07-029, D.11-12-035, or any other Commission decision that imposes a non-bypassable charge for IOU procurement. These elements are explained in more detail below.

Q. Why are you proposing to make the opt-out prospective?

A. Making the opt-out prospective will eliminate any potential for the IOUs to incur stranded costs that could result if an ESP or CCA were allowed to opt-out after the CAM project was approved or operational. This was one of the criticisms of AReM's proposed opt-out mechanism in R.05-12-013, which allowed opting out of CAM projects after they were operational. The Commission found that approach unreasonable.[88] To eliminate that concern, I have restricted the opt-out to prospective CAM procurement only.

Q. Is LSE Opt-Out consistent with the applicable P.U. Code Sections, which provide the Commission with the authority to authorize CAM procurement by the IOUs?

A. Yes. That section of the P.U. Code provides the Commission discretion in its implementation and does not restrict the Commission's ability to approve an opt-out mechanism. Specifically, it says that all benefiting customers in the IOUs' service territory must pay for resources that meet the system or local reliability needs for which the Commission is authorizing IOU investment. When there is an ESP or CCA opt-out, the Commission simply does not authorize IOU investment for the applicable ESP or CCA load, something that is fully within its discretion to do. Further, the Commission continues to show interest in this topic even after the passage of SB 695 and SB 790, as evidenced by its inclusion in the scoping memo for this proceeding.[89] In addition, sub-section 365.1 (c) (2) (A) requires the Commission to authorize CAM procurement only for what is needed.[90] The prospective LSE Opt-Out would *reduce* the need for CAM procurement and thus is not inconsistent with the statute.

Q. Why is a 5-year term reasonable for opting-out of CAM procurement?

A. Each of the three opt-out options includes a 5-year contract term or project life as the basis for the opt-out. A 5-year term corresponds well with the time required for new construction of peaking units which can be completed in less than two years' time, and is

[88] D.10-06-018, p. 74.
[89] LTPP Scoping Memo, R.12-03-014, May 17, 2012, item 10, p. 6.
[90] This P.U. Code section is reproduced in Chapter III, Section A, of this testimony for reference.

within the two- to three-year cycle for LTPP proceedings in which the need for any future CAM procurement would be determined. Thus, the Commission could easily account for termination of such LSE contracts within its biennial LTPP process. In addition, the 5-year is a minimum. Longer-term contracts would be equally acceptable. Further, 5-year or longer-term contracts pose risk for ESPs and CCAs that IOUs do not face, because of their guaranteed cost recovery for the term of the CAM contract. Consequently, a 5-year contract term for LSE Opt-Out is reasonable given these considerations.

ii. Timing of LSE Opt-Out Application

Q. When would LSEs be required to submit their opt-out application?

A. The option to apply for an opt-out would be available to an LSE once the Commission issues a decision approving the need for CAM procurement by an IOU, which is most likely to occur in a LTPP proceeding. In the proposed process discussed in Chapter IV, Section D above, the Commission would issue such a decision in stage one and would identify both the quantity of MWs that may be subject to a future CAM procurement and the required CAM resource characteristics, such as system, local or "flexible" RA capacity This decision would trigger the LSE's option to request an opt-out. The LSE could submit the opt-out application anytime after that decision is approved, but before the IOU identifies a short list of potential winning bidders in its RFO process. If the IOU proposes UOG to meet the CAM need, LSEs would have the option to submit an application anytime after the IOU submits its UOG application to the Commission, but before a decision is rendered by the Commission in that proceeding.

iii. Load-Ratio Share Opt-Out

Q. How would the Load-Ratio Share Opt-Out work?

A. This option would be available to an LSE, once the Commission issues a decision approving MWs of unmet need that may be subject to CAM procurement by an IOU in stage one of the process discussed above. The Commission decision would identify the specific need in MWs, whether system or local resources or specific operational characteristics are needed, and the time frame of the need. LSEs would then have the option to apply to the Commission to opt-out of that prospective CAM procurement.

Q. What must the LSE include in the application?

A. For Load-Ratio Share Opt-Outs, the LSE must demonstrate that it will procure its proportional share of the prospective CAM MWs, as follows:

- *Quantity* – The LSE must demonstrate that it has signed a contract to procure RA resources or plans to build a RA resource on its own to provide MWs at least equal to its load-ratio share of the prospective CAM MWs. For example, if the Commission has determined 500 MW of prospective CAM need for an IOU's service territory and the LSE opting-out has a current load-ratio share of 5% in the IOU's service territory, that LSE could qualify for the opt-out by procuring or building at least 25 MW. The load-ratio share is measured based on the LSE's peak load in the IOU service territory for which the Commission has approved the future CAM procurement and using the most recent California Energy Commission ("CEC") load forecast, as applicable, at the time the opt-out is being requested. In addition to procuring generation resources, an ESP or CCA could also qualify for the opt-out by developing a multi-year demand response or energy efficiency program or by procuring or installing distributed generation ("DG") equal to the required amount, so long as these resources are capable of providing RA.

- *Resource Type* – The procured megawatts of capacity must provide System or Local RA capacity, in accordance with the need determined by the Commission. Also, the LSE must provide an equivalent or better addition to the system than what the Commission has authorized for the prospective CAM procurement. For example, if the Commission has determined that the prospective CAM procurement could be any type of resource, existing, re-powered or new, the LSE seeking to opt-out could also procure from any type of resource: existing, re-powered or new. However, if the Commission has designated that the future capacity must be new construction, the LSE opting-out would have to procure or construct new RA capacity to qualify. If the Commission specified a certain Local RA area, the LSE would have to provide resources in that local area. Again, demand response, energy efficiency, and DG would also qualify as appropriate resource types, provided they met RA capacity requirements.
- *Resource Characteristics* – The LSE must provide equivalent or better resource characteristics for the opt-out and meet all applicable RA requirements. For example, if the Commission has determined that the prospective CAM procurement must provide load-following capability, but regulation was not needed, the LSE would be obligated to provide RA capacity that at least could provide load following to the system.
- *Term* – The LSE must demonstrate a contract term or project life of at least 5 years, as discussed above. In addition, the LSE's contract term must begin or the project must be operational no later than the date on when the prospective CAM need begins, as determined by the Commission.

This Load-Ratio Share Opt-Out provides LSEs with an incentive to avoid the CAM by contracting with generators under multi-year contracts. In addition, the flexibility to sign 5-year contracts before a new CAM procurement is imposed will encourage LSEs to procure new generation and allow the Commission to minimize the IOU's CAM procurement in the first instance.

Q. Does load migration for direct access and CCA customers need to be addressed under this option?

A. No. ESPs and CCAs will manage that risk within their portfolios and, for ESPs, within the contracts they execute with their customers. As the LSE's load comes and goes, the MW of CAM opt-out would remain unchanged, although ESPs and CCAs may sell what becomes excess to their portfolio to some other entity that needs it due to load migration or load growth. Therefore, it is unnecessary to develop transfer or accounting rules to address load migration.

Q. Why is the Load-Ratio Share Opt-Out approach reasonable?

A. The ESP or CCA using this opt-out will have demonstrated that it has procured a comparable RA resource for a designated term to meet CAISO reliability needs. The LSE also assumes 100% of the risk that it is able to recover its RA procurement costs from its customer base. It has no cost recovery guarantee, as do the IOUs. This fully meets all of the Commission's goals for the RA program and in authorizing CAM procurement. Moreover, this opt-out option provides LSEs with the incentive to procure, thereby minimizing the need for CAM procurement or CAISO backstop, which are additional goals of the Commission.

iv. Load-Based Opt-Out

Q. What is the Load-Based Opt-Out?

A. The ESP or CCA would elect Load-Based Opt-Out, if it could demonstrate to the Commission that it is fully resourced at least 5 years into the future to meet the RA capacity requirements associated with its current peak load and projected load growth as determined by the CEC. This demonstration would include a showing that the LSE has procured RA capacity from a mix of existing and new resources and meets any operational characteristics required by the Commission, as well all RA requirements. In addition, the LSE's showing would include RA contracts that increase as load grows. So, if the LSE's load is 90 MW in year 1, but projected to be 100 MW in year 5, the LSE would have to show RA contracts increasing from 90 to 100 MW during the opt-out period. The contracts could be a portfolio of RA capacity resources or one RA resource, at the LSE's election. As with the other opt-out options, demand response, energy efficiency and DG can qualify, provided they meet Commission requirements to qualify as RA resources.

Q. Which LSEs may elect this option?

A. The option is available to any LSE, but CCAs may be more likely to elect this option than an ESP. They have fairly stable load and load growth and are therefore typically more able than are ESPs to enter into contracts with volumes tied to a specific load quantity.

Q. What if the LSE's load changes significantly during the opt-out term?

A. The Commission should allow a 10% cushion to cover an under-forecast of load by the CEC. For example, if the CEC projects the LSE's load to be 100 MW at the end of the 5-year period, the LSE must demonstrate RA contracts to cover 100 MW 5-years out. With the 10% cushion, the CAM opt-out would remain in place for the LSE's load for the 5-year period, with no additional CAM payments imposed, as long as the LSE's forecast load remains at 110 MW or lower during the opt-out term. However, if the CEC projects the LSE's load to exceed 110 MW at some point during the opt-out period, the MWs in excess of 110 MW would be subject to any new CAM procurement authorized by the Commission. However, the LSE would have the option to request either the Load-Ratio Share Opt-Out or Customer-Based Opt-Out (discussed below) for the incremental forecast load and thereby avoid the CAM charge, if the Commission approves the additional opt-out requested.

Q. Does load migration for direct access or CCA customers need to be addressed under this option?

A. That may be necessary, but the Commission should not have to be involved. Load migration will be addressed as a contractual issue between the ESP and its customers. It will also be up to the ESP or CCAs opting out to develop the necessary transfer or accounting rules to address load migration or to manage the risk within its own portfolio.

Q. Why is this approach reasonable?

A. The ESP or CCA using this approach will have demonstrated that it has taken full responsibility to meet its RA requirements for its entire load and load growth for the designated term, provided a mix of existing and new resources and provided operational characteristics required by the Commission to meet reliability needs. This fully meets all of the Commission goals for the RA program and in authorizing CAM procurement. In addition, the LSE has assumed 100% of the risk that its load growth will materialize as projected and that economic downturn or other adverse conditions will not significantly reduce its load. Moreover, this opt-out option provides LSEs with the incentive to procure, thereby minimizing the need for CAM procurement or CAISO backstop, which are additional goals of the Commission.

v. Customer-Based Opt-Out

Q. How would the Customer-Based Opt-Out work?

A. This is a variation of the Load-Based Opt-Out, but an approach that may better fit the business model of the ESPs, although CCAs could elect this option as well. Customers of ESPs tend to sign shorter-term contracts to retain flexibility to switch retail providers. Accordingly, ESPs have limitations on their ability to enter into multi-year procurement contracts for RA. With this option, LSEs would tie their opt-out request to a specific set of customers for which they have signed multi-year service contracts with a term of at least 5 years. The LSE would submit a confidential application to the Commission identifying the customers for which it is requesting the opt-out, the total MWs of the requested opt-out, the term of the opt-out and providing the associated RA contracts to supply the opt-out load. As for the Load-Based Opt-Out, the LSE's demonstration would include a showing that the LSE has procured RA capacity from a mix of existing and new resources and meets any operational characteristics required by the Commission, as well all RA requirements. As with the other opt-out options, demand response, energy efficiency and DG can qualify, provided they qualify as RA resources.

Q. Does load migration for direct access or CCA customers need to be addressed under this option?

A. No. This approach avoids the need to accommodate load migration. The ESPs will only opt-out for the specific customers and the associated multi-year RA capacity contracts used to serve those customers. Because those customers are locked-in for that term, they will not be migrating. Therefore, it is unnecessary to develop transfer or accounting rules to address load migration. CCAs will manage the risk within their own portfolios.

Q. Why is this approach reasonable?

A. The ESP or CCA using this approach will have demonstrated that it has taken full responsibility to meet its RA requirements for a specific set of customers with which it has either a long-term contractual relationship (in the case of ESPs) or confidence that the load will be retained for the long term (in the case of CCAs). Further, the LSE is obligated for the designated term, provides a mix of existing and new resources, and provides operational characteristics required by the Commission to meet reliability needs. This fully meets all of the Commission's goals for the RA program and in authorizing CAM procurement. Moreover, this opt-out option provides LSEs with the incentive to procure, thereby minimizing the need for CAM procurement or CAISO backstop, which are additional goals of the Commission.

vi. Eligibility for Opt-Out

Q. Which LSEs would be eligible to opt-out of the CAM in your proposal?

A. Only non-IOU LSEs would be eligible to opt out of the CAM, specifically ESPs and CCAs. When AReM's LSE Opt-Out proposal was considered in R.05-012-013, the Commission expressed concern that only non-IOUs could opt-out under AReM's proposal.[91] AReM/DACC/MEA have considered the Commission's concerns, but continue to believe that only non-IOUs should be eligible to opt-out for a number of reasons.

[91] D.10-06-018, p. 74.

First, this restriction will serve to mitigate, in part, the anti-competitive effects inherent in the imposition of the CAM. As noted above, the CAM creates anti-competitive effects by allowing one set of LSEs (*i.e.* IOUs) to procure capacity on behalf of other LSEs, despite a uniform obligation on the part of *all* LSEs to meet the RA capacity requirements. Thus, ESPs and CCAs are burdened with unknown and unquantifiable costs that are imposed on their customers and unknown credits that are imposed on their RA resource portfolios by their competitors. By limiting the opt-out to ESPs and CCAs, these anti-competitive effects will be mitigated to some extent.

Second, the LSE Opt-Out proposal provides ESPs and CCAs with the opportunity to exert some control over their own RA portfolios and stabilize the costs to their customers, as well as to take advantage of a concrete incentive to enter into multi-year forward contracts.

Third, the Commission's concern that prohibiting the IOUs from opting-out of the CAM represents "disparate treatment for LSEs"[92] is misguided. CAM already imposes "disparate treatment" on LSEs, in which only the IOUs can recover costs for procurement from their competitors. The AReM/DACC/MEA proposal levels the playing field.

Fourth, IOU opt-out suggests that the IOUs would have the right to ignore a CAM authorization and instead, procure some other resources for which they have no similar authorization. Would the IOUs in this instance still receive guaranteed cost recovery of their preferred resources? Of course not, and therefore the idea of IOU opt-out (unless they want to procure at their shareholder expense) is somewhat non-sensical.

[92] D.10-06-018, p. 74.

Fifth, D.10-06-018 did not address how Senate Bill ("SB") 695 modified the CAM, which I address below.[93] The decision itself notes that SB 695 modified the CAM, but any necessary changes would be considered in a future proceeding.[94] Moreover, as discussed above, LSE Opt-Out is necessary to comply with SB 790, which requires the Commission to ensure CCAs are able to "maximize" use of generation resources of their own choosing to serve load.

Q. Did SB 695 address the Commission's concern in D.10-06-018?

A. Yes. In D.10-06-018, the Commission stated a concern that prohibiting IOUs from opting-out of the CAM would "create a disincentive for IOUs to commit to new resources."[95] However, the Commission determined in D.11-05-005 that SB 695 eliminated the IOUs' ability to elect the CAM.[96] In short, there should be no more concern about eligibility rules creating a disincentive for the IOUs to procure new resources.

In fact, the IOUs do not seem to be concerned about assuming an obligation to procure resources on behalf "all benefiting customers." They proposed to expand CAM treatment to procurement of combined heat and power ("CHP") facilities in a joint settlement, which the Commission approved in D.10-12-035.[97] If the IOUs, or the Commission for that matter, were significantly concerned that the IOUs would desire or require an opt-out from the CAM, the joint settlement and resulting Commission decision should clearly

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[93] Specifically, the provisions of SB 695 embodied in PU Code § 356.1 (c) (2) (A).
[94] D.10-06-018, p. 75.
[95] D.10-06-018, p. 74.
[96] D.11-05-005, pp. 6-7; and Ordering Paragraphs 1 and 2, p. 19.
[97] D.10.12-035, pp. 11-12 and Ordering Paragraph No. 5, pp. 68-69.

have addressed that concern. My conclusion is that the IOUs find the SB 695 CAM requirements and associated cost recovery acceptable.

B. Effect On Cost Allocation From Approved LSE Opt-Out

<u>Witness</u>: Mark Fulmer

Q. If the Commission approves an LSE's application to opt-out from CAM procurement, how should the CAM costs be allocated in a "fair and equitable" manner to the remaining customers?

A. Allowing for LSE opt-out does not materially change either the RA capacity allocation or customer CAM rate calculation. On the RA capacity allocation side, the LSEs that have opted out simply are not included in the calculations. On the cost side, the loads of the opted-out customers are not included in the allocation and they are not charged the CAM charge. As it is consistent with the overall CAM process, it would not create any stranded costs or shift costs from one set of customers to another.

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENT A: WITNESS QUALIFICATIONS

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EXPERIENCE

1/02 – Present Principal, RTO Advisors, L.L.C., Redwood City, California

Provides consulting services promoting competition in wholesale and retail energy markets; negotiates complex arrangements; advises on regulatory proceedings; provides testimony on regulatory proceedings. Key clients include: Alliance for Retail Energy Markets, Arizona Public Service Company, Cargill, Constellation NewEnergy, ConEdison Solutions, Direct Access Customer Coalition, Direct Energy, Energy Curtailment Specialists, Noble Americas Energy Solutions, PacifiCorp, Retail Energy Supply Association, Safeway, Shell Energy, and Wal-Mart. Activities include:

- Advocating proposals regarding resource adequacy and capacity markets before CPUC and CAISO.
- Advocating competitive-neutral Smart Grid policies.
- Advising on demand response policies at the CPUC and CAISO, including implementing demand response bids in CAISO markets.
- Advocating policies in CAISO markets, including scarcity pricing, convergence bidding, and congestion revenue rights (CRRs).
- Advising on renewable issues related to cost allocation of utility procurement and integration with CAISO operations.
- Advised on compliance with CAISO's market monitoring and CPUC resource adequacy programs.
- Provided FERC testimony regarding anti-competitive provisions for transmission access on the Pacific Northwest-Southwest Intertie.
- Offering strategies for entering retail markets in California.
- Monitoring and advocating equitable market rules for competitive retail providers.
- Identifying and mitigating anti-competitive proposals in retail markets.
- Assessed state-of-art of technology for geologic sequestration of carbon.
- Advised on recovering monies due retail suppliers in PG&E's bankruptcy.
- Assisted in obtaining transmission service for new power plant in Nevada.

11/96 – 12/01 Sr. Director, Global Government Affairs, Enron Corp., San Francisco, CA

Key objectives – open competitive markets and make them work. Managed SF office for Enron Government Affairs. Directed legislative and regulatory efforts for California. Managed outside legal representation. Some key accomplishments:

- Enron's lead for CAISO and PX activities and rules for market opening at the CPUC.
- Gained FERC order that CAISO governance be modified to eliminate state influence.
- Gained CAISO Board approval for tradeable transmission rights.
- Lobbied successfully to delay initial market opening by only 3 months (from 1/98 to 4/98).
- Argued successfully to delay suspension of direct access for 7 months in 2001.
- Spearheaded successful effort to gain CPUC approval for competitive markets in metering and billing.
- Created retail coalition that gained initial approval for statewide retail direct access tariffs at CPUC.
- One of the founders of Alliance for Retail Energy Markets (AReM), an alliance of ESPs active in promoting competitive markets.
- Responsible for ensuring Enron readiness to enter retail and wholesale markets by April 1998.

10/83-11/96 ISO Team Leader, Director of Transmission Policy and Pricing, and Principal Contract Negotiator, Pacific Gas and Electric Company, San Francisco, CA

Led deregulation team to develop CAISO working jointly with other utilities and stakeholder groups. Led PG&E's efforts to formulate and implement strategy on other deregulation efforts, such as transmission access policy and interutility arrangements.

- Led PG&E team on FERC filing made April 1996 proposing new market structure and tariffs for California, including ISO and PX.
- Negotiated sales of power and transmission services with revenues to PG&E of more than $25 million annually.
- Obtained $18 million in capital from three utilities for a co-tenant transmission arrangement.
- Led team for PG&E's open access transmission tariff -- first in the nation to meet FERC's NOPR requirements for open access.

5/83-10/83 Licensing and Environmental Specialist, International Engineering Company, Inc., San Francisco, CA

Evaluated effectiveness for EPRI of DOE loan program for small hydro facilities.

11/82-5/83 Independent Hydropower Consultant, Pullman, WA

Prepared portion of FERC licenses for six small hydro projects in Montana and Idaho.

2/82-10/82 **Hydropower License Coordinator, Tudor Engineering Co., San Francisco, CA**
Directed preparation of FERC license applications for hydropower projects, prepared environmental assessments, directed subcontractors, and negotiated with agencies.

5/80-1/82 **Sr. Energy and Resource Analyst, INTASA, Inc., Menlo Park, CA**
Managed large multidisciplinary project to assess expanded hydropower development for the National Hydropower Study; assisted FERC in evaluating effects of PURPA on development of small hydropower and geothermal; managed staff and subcontractors.

9/76-5/80 **Sr. Resource Analyst, SRI International, Center for Resource and Environmental Systems Studies, Menlo Park, CA**
Managed complex scientific projects and conducted environmental and energy studies for clients in industry and government, including: projecting development of small-scale hydropower, biomass and geothermal projects stimulated by PURPA; determining water resource limitations in siting synthetic fuels plants; and modeling mirex in Lake Ontario.

9/75-9/76 **Hydrogeologist, Williams Brothers Engineering Co., Tulsa, OK**
Prepared water demand study and water management plan for Navajo Nation.

11/73-9/75 **Research Analyst, Department of Natural Resources, Madison, WI**
(Part- and full-time) Coordinator for Mine Reclamation Program; developed water use data system; evaluated solid waste plans.

RELATED EXPERIENCE

Treasurer, Association of Women Geoscientists, 1983-85: Developed accounting procedures for non-profit corporation; filed for non-profit status; established budget, prepared quarterly and annual financial reports, and federal/state income taxes.

Instructor, Washington State University, Pullman, WA, 1983: Developed course entitled, "Coping with Technology," for students with computer and math anxiety.

AWARDS

Kent Wheatland Memorial Award, 2001: For integrity and courage in fighting for competitive markets; first annual award given by the Western Power Trading Forum.

Chairman's Excellence Award, PG&E, 1989: For gaining FERC's acceptance of pathbreaking interutility contracts.

Wall of Fame Award, PG&E's Department of Electric Supply, 1992: For gaining CPUC acceptance of locational transmission costs as part of the QF bidding program.

Wall of Fame Award, PG&E's Department of Electric Supply, 1989: For completing and filing with FERC a unilateral rate filing for the Sacramento Municipal Utility District in 6 weeks.

EDUCATION

M.S., 1975, Water Resources Management, College of Engineering, University of Wisconsin.

B.S., 1973, Geology, State University of New York, Fredonia.

PREPARED TESTIMONY SUBMITTED

CPUC

A.11-11-017, Testimony filed May 16, 2012 on PG&E's Smart Grid Pilots, on behalf of AReM and DACC.

A.08-06-001, A.08-06-002, A.08-06-003, Testimony filed November 24, 2008 on IOUs 2009-2011 Demand Response Programs, on behalf of AReM.

R.06-02-013, Long-Term Procurement Proceeding, Phase 2, Testimony filed March 2, 2007 on behalf of AReM.

R.05-06-040 Order Instituting Rulemaking to Implement Senate Bill No. 1488 Relating to Confidentiality of Information, Testimony filed October 28, 2005, on behalf of AReM and Coral Power.

FERC

ER07-882-000, PacifiCorp, testimony filed September 13, 2007 on behalf of PacifiCorp.

ER00-565-003, PG&E, deposition provided September 4, 2003, on behalf of Sacramento Municipal Utility District.

Wholesale Distribution Tariff, witness for Enron Corporation, 1997.

ARBITRATION

Case No: 74Y19800931 03 VSS – Micrel vs. Chevron Energy Solutions, Hearing March 9, 2004, American Arbitration Association, on behalf of Chevron Energy Services.

MARK E. FULMER

PROFESSIONAL EXPERIENCE

Principal
MRW & Associates, LLC
(1999 - Present)

Conducts economic and technical studies in support of clients involved in regulatory and legislative proceedings, power project development and end-user energy option assessment. Work includes review of air emissions regulations and their impact on power costs; pro forma analysis of cogeneration and distributed generation facilities; economic analysis of end-use energy-efficiency projects.

Project Engineer
Daniel, Mann, Johnson & Mendenhall
(1996 - 1999)
Acted as project manager and technical advisor on energy efficiency projects. Work included management of PG&E program to promote innovative energy efficient technologies for large electricity users. Coordinated the implementation of an intranet-based energy efficiency library. Directed technical and market analyses of small commercial and residential emerging technologies.

Associate
Tellus Institute
(1990-1996)
Advised public utility commissions in five states on electric and gas industry deregulation issues. Submitted testimony on the rate design of a natural gas utility to the Pennsylvania Public Utilities Commission. Testified before the Hawaii PUC on behalf of a gas distribution utility concerning a competing electric utility's demand-side management plan. Analyzed national energy policies for a set of non-governmental agencies, including critiquing the DOE's national energy forecasting model. Developed model to track transportation energy use and emissions and used the model to evaluate state-level transportation policies. Developed model to track greenhouse gas emission reductions resulting from state-level carbon taxes.

Research Assistant
Center for Energy and Environmental Studies, Princeton University
(1988-1990)
Researched the technical and economic viability of gas turbine cogeneration using biomass in the cane sugar and alcohol industries. First researcher to apply "pinch" analysis and a mixed-integer linear programming model to minimize energy use in cane sugar refineries and alcohol distilleries.

EDUCATION

M.S.E., Mechanical and Aerospace Engineering, Princeton University, 1991
B.S., Mechanical Engineering, University of California, Irvine, 1986

Selected Publications

1. A Technical and Economic Assessment of the Co-Production of Electricity and Alcohol From Sugar Cane. Presented at the *International Engineering Conference on Energy Conversion (IECEC-90)*. American Institute of Chemical Engineers. New York, NY. August 1990. Principal author and presenter.

2. Cogeneration Applications of Biomass Gasifier/Gas Turbine Technologies in the Cane Sugar and Alcohol Industries. Proceedings, *Energy and Environment in the 21st Century*, MIT Press. Cambridge, Massachusetts. 1991. Co-author.

3. The Environmental Impacts of Demand-Side Management. Electric Power Research Institute report TR-101673. 1992. Co-author.

4. The Role of Gas Heat Pumps in Electric DSM. Presented at the 6th National Demand-Side Management Conference. Miami Beach, Florida. March 1993. Principal author and presenter.

5. Applying an Integrated Energy/Environmental Framework to the Analysis of Alternative Transportation Fuels. Invited paper at the European Council for an Energy Efficient Economy (ECEEE) 1993 Summer Study. Principal author.

6. Mistakes, Misconceptions, and Misnomers in DSM Cost-Effectiveness Analysis. Peer reviewed paper at the ACEEE 1994 Summer Study. Principal author and presenter.

7. A Social Cost Analysis of Alternative Fuels for Light Vehicles. *Energy Strategies for a Sustainable Transportation System*, ACEEE. Washington, DC. 1995.

8. Strategies for Reducing Energy Consumption in the Texas Transportation Sector. Project for the Texas Sustainable Energy Development Council. Austin, Texas. June 1995. Co-author.

9. Evaluation of Food Processing Effluent Treatment Alternatives. Paper presented at the American Chemical Society meeting, Las Vegas, Nevada. December 1997. Co-Author.

10. Market Transformation Effect Indicators for Government, Utilities, Retailers and Manufacturers. Invited panelist in a roundtable discussion at the American Council for an Energy Efficient Economy (ACEEE) 1998 Summer Study.

11. California: Crisis Over? Project Finance NewsWire, Chadbourne & Parke. October 2001. Co-author.

12. California: Back to Basics or Déjà Vu? Natural Gas & Electricity, Volume 20, Number 12. July 2004. Co-author.

13. Nuclear Fuel Reprocessing: Issues and Future Prospects. Report for the California Energy Commission. (Final Draft). March 2006. Co-author.

14. AB 1632 Assessment of California's Operating Nuclear Plants. California Energy Commission, CEC-100-2008-005-F. October 2008. Co-author.

15. Framework for Evaluating Greenhouse Gas Implications of Natural Gas-fired Power Plants in California. California Energy Commission, CEC-700-2009-009-F. May 2009. Co-author.

Prepared Testimony

1. Rhode Island Public Utilities Commission No. 2025
   Prepared Testimony on Behalf of Rhode Island Department of Public Utilities and Carriers (Commission Staff). Testimony addressed the costs, savings, and cost-effectiveness of the proposed demand-side management programs of Providence Gas Company. April 1993.

2. Pennsylvania Public Utility Commission R-943029
   Prepared Testimony on Behalf of the Pennsylvania Office of Consumer Advocate. Testimony reviewed 1307(f) filing of Columbia Gas of Pennsylvania, particularly the impact of the proposed gas cost recovery mechanism on residential customers. May 1994.

3. Public Utilities Commission of the State of Hawaii No. 94-0206
   Prepared Testimony on Behalf of the Gas Company of Hawaii (Gasco). Testimony identification of Gasco's concerns regarding HECO's proposed DSM programs for competitive energy end-use markets. December 1994.

4. FERC Docket Nos. EL00-95-075 and EL00-98-063
   Affidavit on Behalf of Duke Energy Trading and Marketing LLC. March 20, 2003.

5. CPUC Rulemaking 01-10-024 Prepared
   Testimony on Behalf of the Alliance for Retail Energy Markets. Testimony addressed the utility procurement plans with respect to resource adequacy. June 23, 2003.

6. CPUC Rulemaking 01-10-024
   Rebuttal Testimony on Behalf of the Alliance for Retail Energy Markets. July 14, 2003.

7. Arizona Corporation Commission No. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630. E01933A-02-0069, E-01933A-98-0471
   Rebuttal Testimony on Behalf of Constellation NewEnergy, Inc. and Strategic Energy, L.L.C. Testimony addressed the future of the Arizona Independent System Administrator. July 28, 2003.

8. Arizona Corporation Commission No. E-00000A-02-0051
   Reply Testimony on Behalf of Constellation NewEnergy, Inc. and Strategic Energy L.L.C. August 29, 2003.

9. Arizona Corporation Commission No. E-01345A-03-0437
   Direct Testimony on Behalf of Constellation NewEnergy and Strategic Energy, Inc. February 3, 2004.

10. Arizona Corporation Commission No. E-01345A-03-0437
Cross Rebuttal Testimony of Mark E. Fulmer on Behalf of Constellation NewEnergy and Strategic Energy, Inc. March 30, 2004.

11. CPUC Rulemaking 03-10-003
Direct Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Community Choice Aggregation Transaction Costs. April 15, 2004.

12. CPUC Rulemaking 03-10-003
Reply Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Cost Responsibility Surcharge for Community Choice Aggregation. May 7, 2004.

13. CPUC Rulemaking 03-10-003
Rebuttal Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Cost Responsibility Surcharge for Community Choice Aggregation. May 20, 2004.

14. CPUC Rulemaking 04-04-003
Testimony of Mark Fulmer on Behalf of Strategic Energy LLC and Constellation NewEnergy concerning the Long Term Procurement Plans of PG&E, SCE and SDG&E. August 6, 2004.

15. CPUC Rulemaking 04-04-003
Rebuttal Testimony of Mark Fulmer on Behalf of Strategic Energy LLC and Constellation NewEnergy concerning the Long Term Procurement Plans of PG&E, SCE and SDG&E. August 20, 2004.

16. CPUC Rulemaking 03-10-003
Opening Testimony of Mark E. Fulmer on Behalf of the City and County of San Francisco on Allocation of Costs for Community Choice Aggregation Phase 2. April 28, 2005.

17. CPUC Rulemaking 04-12-014
Testimony of Mark E. Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning Southern California Edison's Test Year 2006 General Rate Case Application. May 6, 2005.

18. CPUC Rulemaking 03-10-003
Rebuttal Testimony of Mark E. Fulmer on Behalf of the City and County of San Francisco on Allocation of Costs for Community Choice Aggregation Phase 2. May 16, 2005.

19. CPUC Rulemaking 04-12-014
Testimony of Mark E. Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning Southern California Edison's Test Year 2006 General Rate Case Application. May 25, 2005.

20. CPUC Application 06-03-005
Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning Phase 2 of the Pacific Gas and Electric Co.2007 General Rate Case Marginal Cost, Revenue Allocation and Rate Design. October 27, 2006.

21. CPUC Application 07-01-045
    Testimony of Mark E. Fulmer on Behalf of The Alliance for Retail Energy Markets and The California Manufacturers and Technology Association Concerning Southern California Edison's Application to Update is Direct Access and Other Service Fees. June 22, 2007.

22. CPUC Rulemaking 08-03-002
    Testimony of Mark Fulmer Behalf of Debenham Energy, LLC. Concerning Tariffs Supportive of Green Distributed Generation. October 31, 2008.

23. CPUC Application 09-02-022
    Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning Pacific Gas & Electric's 2009 Rate Design Window Application. July 31, 2009.

24. CPUC Application 09-02-019
    Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning the Cost Recovery Proposed By PG&E in its Application to Implement A Photovoltaic Program. August 14, 2009.

25. Superior Court of San Francisco
    Deposition of Mark E. Fulmer on Behalf of the City and County of San Francisco in PG&E v. CCSF. (Verbal deposition only.) September 2, 2009.

26. California Superior Court of San Francisco Court Case No. CGC-07-470086 Testimony of Mark E. Fulmer on Behalf of the City and County of San Francisco in Pacific Gas & Electric Company v. City and County of San Francisco. (Trial exhibits only in electronic file.) September 25, 2009.

27. CPUC Application 09-12-020
    Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning Phase 1 of Pacific Gas & Electric Company's Test Year 2011 General Rate Case. May 19, 2010.

28. CPUC Application 10-03-014
    Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of Pacific Gas & Electric's Test Year 2011 General Rate Case Application. October 6, 2010.

29. CPUC Rulemaking 07-05-025
    Testimony of John P. Dalessi, Mark E. Fulmer, Margaret A. Meal on Behalf of the Joint Parties on a Fair and Reasonable Methodology to Determine the Power Charge Indifference Adjustment (PCIA) and the Competition Transition Charge (CTC). January 21, 2011.

30. CPUC Rulemaking 07-05-025
    Testimony of Mark E. Fulmer on Behalf of the Direct Access Parties Concerning the Transitional Bundled Service Rate, Direct Access Switching Rules, Minimum Stay Provisions, and Energy Service Provider Financial Security Requirements. January 31, 2011.

31. CPUC Rulemaking 07-05-025
    Rebuttal Testimony of Mark E. Fulmer on Behalf of The Direct Access Parties Concerning the Transitional Bundled Service Rate, Direct Access Switching Rules, Minimum Stay Provisions, and Energy Service Provider Financial Security Requirements. February 25, 2011.

32. CPUC Rulemaking 07-05-025
Rebuttal Testimony of John P. Dalessi, Mark E. Fulmer, Margaret A. Meal on Behalf of The Joint Parties on a Fair And Reasonable Methodology to Determine the Power Charge Indifference Adjustment (PCIA) and the Competition Transition Charge (CTC). February 25, 2011.

33. CPUC Rulemaking 07-05-025
Testimony of Mark E. Fulmer on Behalf of the Direct Access Parties Concerning the Transitional Bundled Service Rate, Direct Access Switching Rules, Minimum Stay Provisions, and Energy Service Provider financial Security Requirements. March 28, 2011.

34. CPUC Rulemaking 07-05-025
Reply Testimony of Mark E. Fulmer on Behalf of the Direct Access Parties Concerning the Transitional Bundled Service Rate, Direct Access Switching Rules, Minimum Stay Provisions, and Energy Service Provider financial Security Requirements. March 28, 2011.

35. CPUC Application A.11-03-001, 11-03-002, 11-03-003
Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition and The Alliance for Retail Energy Markets Concerning Competitive Issues in the 2012-2014 Demand Response Program Proposals. June 15, 2011.

36. CPUC Application 11-06-004
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition and the Alliance for Retail Energy Markets concerning PG&E's 2012 Energy Resource Recovery Account (ERRA) and 2012 Generation Non-bypassable Charges Forecast. August 26, 2011.

37. CPUC Application 11-05-023
Testimony of Mark Fulmer on Behalf of the Direct Access Customer Coalition, the Alliance for Retail Energy Markets and the Western Power Trading Forum concerning the Application of San Diego Gas & Electric for Authority to Enter into Purchase power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center, and Quail Brush Power. September 22, 2011.

38. CPUC Application 11-06-007
Testimony of Mark Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of Southern California Edison's Test Year 2012 General Rate Case Application. February 6, 2012.

39. CPUC Application 11-12-009
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition, the Alliance for Retails Energy Markets and the City and County of San Francisco Concerning Pacific gas & Electric Company's Application to Revise Direct Access and Community choice Aggregation Service Fees. May 14, 2012.