Docket No.: R.13-09-011

Exhibit No.: ____________________

Date: May 6, 2014

Witness: Sue Mara

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

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I. INTRODUCTION AND SUMMARY

Q: 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 energy 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 testified before the California Public Utilities Commission ("Commission")?

A: Yes. I have provided testimony on behalf of the Alliance for Retail Energy Markets ("AReM") and/or the Direct Access Customer Coalition ("DACC") in several Commission proceedings, including the Investor-Owned Utilities' ("IOUs" or "utilities") demand response program applications in 2008 (A.08-06-001 to -003). I have also testified before the Federal Energy Regulatory Commission ("FERC"). Attachment A lists the prepared testimony I have submitted since 1997.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of DACC and AReM. DACC is a regulatory alliance of educational, commercial, industrial and governmental customers who have opted for direct access service for some or all of their loads. In the aggregate, DACC member companies represent over 1,900 megawatts ("MW") of demand that is met by both direct access and bundled utility service and about 11,500 gigawatt-hours of statewide annual usage. AReM is a California mutual benefit corporation whose members are electric service providers ("ESPs") and load-serving entities ("LSEs") that provide direct access service and other competitive energy-related products and services to retail end-use customers throughout the state.

Q: What are the interests of DACC and AReM in this proceeding?

A: The members of AReM are actively engaged in selling energy products and services in the direct access market in direct competition with the IOUs, who continue to provide bundled customer service that includes similar products and services. The members of DACC procure all or part of their load from ESPs in the direct access market. As explained below, the manner in which IOUs are allowed to recover the costs of their demand response ("DR") programs – primarily through distribution rates, as opposed to generation rates where they largely belong – is unjustified and unfair, confers an unwarranted competitive advantage to the IOUs by artificially suppressing generation rates, and, as a result, violates principles of competitive neutrality. DACC's and AReM's primary interest in this proceeding is to ensure that the competitive neutrality principles that the Commission has enunciated and mandated are appropriately applied to the IOUs' DR programs, as set forth below in this testimony. This would create a genuine competitive balance in California that (a) allows non-utility LSEs to compete on a fair and equal basis with regulated utilities and (b) reduces barriers to entry for third-party DR Providers, so that they may more effectively and directly interact with customers to craft cost effective, targeted and innovative DR programs that customers, including many of the DACC members, desire.

Q: Please summarize your conclusions and recommendations.

A: I conclude and recommend the following:

Cost Allocation:

- Proper cost allocation is foundational to ensuring competitive neutrality and fairness in DR and retail choice markets and is supported by Commission precedent.
- This proceeding should establish uniform cost allocation principles for utility-run DR programs that ensure competitive neutrality and fairness and which the IOUs would be required to apply when requesting new DR program funding.
- The vast majority of the IOUs' DR program costs are currently recovered through distribution rates, instead of through generation rates where they belong, which harms DR and retail choice markets, provides a competitive advantage to the IOUs, and potentially limits overall market participation by third-party DR Providers.
- The bifurcation of utility-run DR programs into Supply Resources and Load Modifying Resources in Decision ("D.") 14-03-026 provides a simple and rational basis for setting cost allocation principles.
- I propose principles to allocate the costs of utility-run DR programs based on their bifurcation, customer eligibility, and generation-related functions.
- I conclude that the costs of all the utility-run DR programs categorized in D.14-03-026 should be recovered through generation rates.

Utility-Centric Model:

- California has a utility-centric model and participation of third-party DR Providers in the California market has been limited.
- If the Commission wishes to move away from the utility-centric model, it must adopt the proposed cost allocation principles, resolve uncertainties about Resource Adequacy ("RA") value applied to DR programs, and require competitive DR procurement by the IOUs.

Back-Up Generators:

- The Commission should not prohibit use of back-up generators for DR, but instead explore ways in which their use may be acceptable.

Demand Response Auction Mechanism:

- The Commission does not have jurisdiction to require ESPs to procure through the proposed DR auction mechanism.

II. COST ALLOCATION

A. Competitive Neutrality and Fairness

Q. Why is it appropriate to consider cost allocation as a "foundational issue?"

A. The Assigned Commissioner and Administrative Law Judge ("ALJ") identified cost allocation as a "foundational issue" for Phase Two of this proceeding in the November 14, 2013 Scoping Memo[1] at the request of DACC and AReM, who explained that proper

[1] *Joint Assigned Commissioner and Administrative Law Judge Ruling and Scoping Memo*, R.13-09-011, November 14, 2013, p. 9.

cost allocation is fundamental to the success of a competitive DR market.[2] The effect of this "foundational issue" is broader than simply the DR markets, however. Improper allocation of IOU DR program costs also affects the viability of the retail choice market and the ability of ESPs and Community Choice Aggregators ("CCAs") to compete fairly with the IOUs to acquire and serve customers.

Q. **Please describe the Commission's foundational policy decision regarding cost allocation and competitive neutrality.**

A. In D.97-08-056, the Commission ordered the three IOUs to unbundle their rates into separate generation and transmission/distribution components "to promote competition in the electrical generation market."[3] In that Decision, the Commission determined that such unbundling was required to implement the "spirit and letter" of the restructuring legislation, Assembly Bill 1890, and specifically cited Public Utilities Code ("PU Code") Section 330(k)(1), which stated that "in order to achieve meaningful wholesale and retail competition in the electric generation market, it is essential to ... (s)eparate monopoly utility transmission functions from competitive generation functions....," and PU Code Section 368 (b), which required the Commission to separate the IOUs' costs into "individual rate components such as charges for energy, transmission, distribution, public benefit programs, and recovery of uneconomic costs."[4] Further, the Commission specifically prohibited allocation of generation costs to the distribution function:

> In pursuing a policy to promote more efficient generation markets, we

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[2] *Prehearing Conference Statement of the Direct Access Customer Coalition and Alliance for Retail Energy Markets*, R.13-09-011, October 14, 2013, pp. 3-5.

[3] D.97-08-056, p. 4.

[4] D.97-08-056, p. 7.

> reject proposals to allocate to monopoly functions any costs associated with services that are or will be subject to competition. Specifically, ***we will not permit allocations of generation cost to distribution customers***. To do so would compromise market efficiency by producing artificially low utility generation rates (or utility profits which do not correspond to utility risk) and ***provide competitive advantages, which would stifle competition to the utilities***. (emphasis added)[5]

Thus, in making its determination on unbundling, the Commission also explained the potential for competitive harm through improper cost allocation. Specifically, the Commission noted the clear potential for artificially-low utility generation rates that provide competitive advantages to the utilities and stifle competition with improper cost allocation. Although the original vision of Assembly Bill 1890 has changed significantly over the years, and the utility's expanded role in the procurement of generation resources and continued bundled customer service is not what was contemplated in that legislation, the basic requirement for competitive neutrality remains and the Commission has continued its commitment to competitive wholesale and retail markets to this day.

Q. What recent steps has the Commission taken to ensure that the IOUs compete fairly in direct access, CCA and DR markets?

A. There are examples of recent Commission action to ensure competitive neutrality in two recent decisions. First, in Rulemaking ("R.") 11-03-012, the proceeding initiated to determine the distribution of greenhouse gas ("GHG") auction revenues, the Commission

[5] D.97-08-056, p. 8.

mandated equal treatment of direct access and CCA customers, as well as competitively-neutral communications with all retail customers.[6] The Commission specifically stated:

> To ***ensure competitive neutrality*** among investor-owned utilities and CCAs and Energy Service Providers, ***GHG compliance costs must be included in the generation component of customers' rates*** and allocated in the same manner that other generation costs are allocated to bundled customers. (emphasis added)[7]

In other words, the Commission recognized that proper cost allocation was an essential component of ensuring competitive neutrality – and key to that allocation was incorporating the IOUs' GHG-related costs into their generation rates.

Second, in the direct participation phase of the Demand Response Rulemaking (R.07-01-041), the Commission required the IOUs to incorporate into their tariffs mandates to ensure competitive neutrality,[8] an addition made at the request of DR Providers and direct access parties in that proceeding.[9]

Q. Are there fairness issues that the Commission should consider?

A. Yes. In D.13-08-023, the Commission rejected Petition 12-12-010 ("Petition") submitted by DACC and AReM and other parties seeking Commission agreement to review and reform existing cost allocation practices and the mechanisms used to determine non-bypassable charges imposed on departing load customers.[10] In rejecting the Petition, the Commission stated:

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[6] See, for example, D.12-12-033, Finding of Fact 39, p. 168 stating that a "high priority objective" of the proceeding was "maintaining competitive neutrality"; and Finding of Fact 147, p. 186, requiring that customer education and outreach plan be competitively neutral. See also, Ordering Paragraphs 1 (p. 206) and 3 (p. 209).)

[7] D.12-12-033, Finding of Fact 136, p. 184.

[8] D.12-11-025, R.07-01-041, Attachment B, Electric Rule No. 24, Section B.2.a.

[9] See, *Joint Parties' Proposed Direct Participation Rules*, R.07-01-041, May 2, 2011, p. 6. The Joint Parties were EnerNOC, Inc., EnergyConnect, Inc, AReM, and DACC.

[10] P.12-12-010, pp. 2-4.

> The Commission remains committed to ensuring that Community Choice Aggregators and other non-utility LSEs may compete on a fair and equal basis with regulated utilities. Towards this end, we will continue to consider both the mechanics and ***overall fairness of cost allocation*** and departing load charge methodologies proposed in the future, with the specific goal of avoiding cross-subsidization. (emphasis added)[11]

Q. What do you conclude from this review of the history of Commission action on cost allocation and competitive neutrality?

A. I conclude that the Commission has consistently recognized the need to ensure a level playing field when the utilities are put in direct competition with non-rate regulated service providers, like ESPs, CCAs, and third-party DR Providers. Proper cost allocation of the IOUs' DR program costs is an essential component of "fairness" and in ensuring that non-utility LSEs and DR Providers are able to compete on a "fair and equal basis" with the IOUs. As described in the testimony that follows, improper cost allocation undermines competitive markets, discourages participation by competitive third-party providers, and confers an unfair competitive advantage on the IOUs.

B. Action Requested With Respect to Cost Allocation

Q. What Commission action do DACC and AReM request with respect to cost allocation?

A. The Commission previously determined in D.12-04-045 that cost allocation issues "should be considered in a consistent manner across all three utilities and thus are best handled in one proceeding."[12] The Scoping Memo establishes this as the proceeding

[11] D.13-08-023, p. 17.
[12] D.12-04-045, p. 204.

where this will be resolved.[13] To do so, the Commission should establish defined principles in this proceeding that will govern allocation of utility DR procurement and program costs and apply uniformly to each of the IOUs. The IOUs would then be required to comply with these cost allocation principles for all their DR procurement and programs that are adopted as a result of individual utility applications or in their General Rate Cases. Setting such uniform principles will ensure utility DR programs are competitively neutral and consistent throughout the state. Moreover, as long as the IOUs have complied with the Commission-approved uniform cost allocation principles, parties would no longer be required to address this contentious issue in litigation. Below, I recommend specific cost allocation principles for the Commission to adopt in this proceeding.

C. Current Cost Allocation and Levels of Funding

Q. How do the IOUs recover the costs of their DR programs today?

A. In general, DR program costs are currently collected through distribution rates,[14] with a few minor exceptions. Pacific Gas and Electric Company ("PG&E") recovers all of the costs of its DR programs through distribution rates, except for the costs associated with contract incentive payments to third-party DR Providers under the Aggregator Managed Portfolio ("AMP") program, which are recovered from bundled customers through its Energy Resource Recovery Accounts ("ERRA").[15] San Diego Gas & Electric Company

[13] Scoping Memo, *loc. cit.*, p. 9 and Attachment One, pp. 2- 3..
[14] Ibid.
[15] *Pacific Gas and Electric Company's Demand Response Program Proposals for 2015 and 2016,* R.13-09-011, March 3, 2014, pp. 16-17. PG&E recovers the administrative costs of its AMP contracts through distribution rates, as explained in D.12-11-045, p. 67. PG&E does not differentiate the incentive costs (if included here at all) from administrative costs.

("SDG&E") has no AMP contracts,[16] but recovers the energy component of its DR customer incentive payments in its ERRA.[17] SDG&E does not specify in its Bridge Funding request what fraction of the overall incentive budget this represents, but given that DR programs provide mainly capacity incentive payments, I suspect it is minimal. SDG&E's remaining DR program costs are recovered in distribution rates. Unlike PG&E and SDG&E, Southern California Edison Company ("SCE") did not address cost recovery in its March 3, 2014 Bridge Funding request.[18] However, in requesting approval of its AMP contracts for 2011 and 2012, SCE stated that energy payments under the contracts are recovered through ERRA and that other AMP costs, including capacity payments, are recovered through distribution rates.[19] Again, given the fact that DR programs are capacity-oriented, I suspect the amount recovered through ERRA is minimal. I believe the remainder of SCE's DR program costs are recovered through distribution rates.

Q. What level of DR funding for the IOUs has been authorized to date?

A. Table 1 provides what I have been able to parse out from the specified Commission decisions issued since 2009 and also includes the proposed budgets included in the Phase One decision released on April 15, 2014 by ALJ Hymes in this proceeding.

[16] D.12-04-045, p. 188, states that SDG&E cancelled its AMP contracts in early 2011.

[17] *San Diego Gas & Electric Company 2015-2016 Demand Response Program Proposals and Response to Additional Information Pursuant to the Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for Submitting Demand Response Programs*, R.13-09-011, March 3, 2014, pp. 22-23.

[18] *Southern California Edison Company's Demand Response Program Improvement Proposals for Bridge Funding Years 2015-2016,* R.13-09-011, March 3, 2014.

[19] *Application of Southern California Edison Company for Expedited Approval of Five Demand Response Resource Purchase Agreements*, A.12-09-007, September 7, 2012, Table V-4, p. 9.

Table 1 Authorized IOU DR Program Expenditures Since 2009 With Costs Recovered Through Distribution Rates ($ Million)					
IOU	**D.09-08-027[20]**	**D.12-04-045[21]**	**D.13-04-017[22]**	**Proposed Phase One Decision 4/15/14[23]**	**TOTAL**
PG&E	$109.1	$191.9	--	$99.1	$400.1
SCE	$188.8	$196.3	--	$180.5	$565.6
SDG&E	$51.6	$65.8	1.8	$39.1	$158.3
TOTAL	$349.5	$454.0	$12.1	$318.7	$1,124.0

In summary, the Commission has authorized DR program expenditures for the IOUs totaling more than $1 billion since 2009, the vast majority of which I believe has been recovered through distribution rates.[24] If the current requests included in the Phase One proposed decision are granted, this works out to approximately $1 per megawatt-hour of what I believe to be generation-related costs recovered through distribution rates.[25]

D. Effect of Current Cost Allocation on Markets and Costs to Consumers

Q. What are the effects of recovering IOU DR program costs through distribution rates?

A. All customers pay distribution rates as a non-bypassable charge.[26] When generation-related DR costs are allocated to distribution rates, there are several harmful effects.

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[20] D.09-08-027, p. 1.

[21] D.12-04-045, p. 1.

[22] D.13-04-017, pp. 50-52. This Decision primarily authorized SCE and SDG&E to shift costs among different DR programs, but did authorize some incremental budget amounts for SDG&E.

[23] Proposed Phase One Decision, issued April 15, 2014, R.13-09-011, pp. 27, 32 and 37.

[24] These authorized amounts may not be entirely additive. For example, unspent DR program funds in one funding cycle may be carried over to the next.

[25] Calculated as the sum of the three IOUs' requests for 2015 and 2016 ($318.7 million) divided by 2 ($159.4 million per year) divided by 2013 utility retail sales from their respective FERC Form 1's (190 million MWhs).

[26] Although customers connected at transmission-level voltages pay *de minimis* distribution rates – two orders of magnitude less than those connected at lower voltages.

First and foremost are the anti-competitive cost shifting and cross-subsidies that result between bundled utility customers and direct access customers, when direct access customers are forced to pay for a portion of the IOUs' generation-related costs in their distribution rates. Procurement by the IOUs of DR capacity and energy consumption reduction services through their DR programs substitutes for procurement of capacity and energy from a generating plant, which the IOUs own or contract with for the output. The Commission authorizes the IOUs to recover their supply costs associated with such generating plants through generation rates, and DR costs should be treated the same way.[27] When all or some portion of the DR program costs are recovered in the distribution revenue requirement instead of being recovered through the generation revenue requirement, the generation rates for the IOUs' bundled electricity service are artificially suppressed, as costs are shifted from bundled customers to direct access customers. This results in an unfair competitive advantage to the IOUs and is a disadvantage to the ESPs and CCAs who directly compete with the IOUs for customers. When current or prospective customers of ESPs and CCAs compare an IOU's generation rates to the ESP/CCA prices, they do not see the true cost of the IOUs' generation portfolio because of the subsidies included in their distribution rates. In short, when the generation component of IOU rates is inappropriately whittled down in this manner, the price comparison that retail choice customers must make between utility rates and competitive prices is artificially skewed, diminishing competitive opportunities and distorting the retail market. Such outcomes impede the direct access and CCA markets and are directly contrary to Commission policy to ensure competitive neutrality.

[27] Capacity costs recovered through the Cost Allocation Mechanism ("CAM") are, of course, an exception to this rule.

Second, allowing recovery of utility DR costs from all customers through non-bypassable rates or charges is a barrier to entry for third-party DR Providers, because the customers they would serve through their own DR program offerings are required to pay for the utilities' programs, making the third-party program less competitive than the utilities' ratepayer-subsidized DR programs. [28] A DR market dominated by the IOUs eliminates the downward pressure on prices that broader and more robust competition would create and thus creates higher costs for consumers.[29]

Third, the existence of the IOUs' ratepayer-subsidized DR program will in turn cause third-party DR Providers to choose to spend their limited market development dollars to engage in other markets where the playing field is less skewed and opportunities for competitive success are greater, or must confine their participation to the utility-based programs.

Fourth, the prescriptive DR programs offered by the IOUs often do not fit the customers' needs, thereby discouraging or prohibiting participation by customers. Further, California's market lacks the third-party DR Providers to bring innovative DR products and services that can be tailored specifically to meet the needs of California's consumers.

Q. Has the California Independent System Operator ("CAISO") raised concerns about the effect of improper cost allocation on competitive DR markets?

[28] See: D.12-04-045, pp. 201-202; and *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 2012-14 Demand Response Program Proposals*, A.11-03-001 et al, June 15, 2011.p. 12-20.

[29] See, for example, *Customer Choice in Electricity Markets: From Novel to Normal*, prepared for COMPETE Coalition by Dr. Philip R. O'Connor, November 15, 2010, pp. 5 -6; and *Embrace Electric Competition or Its Déjà vu All Over Again,* by Frank Huntowski, Neil Fisher and Aaron Patterson, The NorthBridge Group, October 2008, pp. 62-71, for a discussion of competition in other industries and the effects on prices, innovation and products for consumers.

A. Yes. In addition to DACC and AReM, the CAISO raised this same issue in the previous DR policy proceeding, R.07-0-041. The CAISO explained that California's current cost allocation approach creates an "un-level and anti-competitive playing field," which prevents a "viable competitive" DR market from taking "root."[30] The CAISO reasoned that improperly allocating IOU DR program costs to distribution rates is both a "major policy issue" and a "current barrier to the development of a competitive demand response market."[31]

E. Recommended Cost Allocation Principles

Q. What cost allocation principles do you recommend the Commission adopt?

A. In a March 2014 decision in Phase Two of this proceeding (D.14-03-026), the Commission determined that utility DR programs should be bifurcated into two categories: Supply Resources and Load Modifying Resources.[32] That adopted categorization provides a rational and simple basis for cost allocation principles, as follows:

- <u>Supply Resources</u> are integrated into the CAISO's wholesale energy markets,[33] thereby performing the same function as generation resources. The associated Supply Resource costs must be recovered the same way as they are for generation resources – through generation rates.

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[30] *Initial Response on the Assigned Commissioner and Administrative Law Judge's Ruling Soliciting Responses from Questions Arising from Federal Energy Regulatory Commission Order 745 and 745A*, CAISO, R.07-01-041, August 17, 2012, p. 7; see also, discussion on pp. 8-10.
[31] *Ibid*, p. 8.
[32] D.14-03-026, Ordering Paragraph 1, p. 28.
[33] D.14-03-026, Ordering Paragraph 3, p. 28.

- Load Modifying Resources are resources that "reshape or reduce the net load curve."[34] Costs associated with this category of DR resource should be allocated depending on: (a) the customers to whom the program is available and applicable; and (b) whether the program functions as a substitute for generation by providing a Resource Adequacy ("RA") capacity credit or other generation-like function, such as peak-shifting. Specifically, if the Load Modifying program is a pricing tariff, such as time-of-use ("TOU") rates or dynamic pricing tariffs, such programs are solely available and applicable to bundled utility customers and the costs should therefore be recovered solely from those bundled utility customers. On the other hand, if the Load Modifying program is available and applicable to all customers, including direct access customers, but also provides an RA credit (or other generation-like function), the program functions as a substitute for generation and must be recovered through generation rates, with the RA benefits retained by the bundled customers. I describe this cost allocation approach in more detail below.

Q. Please explain the rationale for recovering the costs of Supply Resource DR through generation rates.

A. The main benefits of Supply Resource DR are to reduce peak demand on the electrical system, reduce the need to procure new peaking resources, and potentially to help integrate intermittent renewable resources into the grid. In other words, this kind of DR directly substitutes for generation supply.

[34] D.14-03-026, Ordering Paragraph 2, p. 28.

The CAISO agrees that DR performs a generation-like function in the wholesale market. In its 2009 Annual Report, the CAISO discussed:

> … the need to translate retail demand response programs managed by utilities or aggregators into wholesale products that ***look and act like generators.*** This would mean the ISO could ***use demand response the same way as thermal power plants*** in advance of real time as part of the total resources available to serve load. (emphasis added)[35]

This is exactly the function provided by DR Supply Resources. They are designed to "look and act like generators" in the CAISO's wholesale markets. Thus, their costs should be allocated the same way that generator costs are allocated – through generation rates.

As further evidence, the Commission has approved utility DR programs that can be bid into CAISO markets as a Proxy Demand Resource ("PDR").[36] In its order approving PDR, FERC concurred that PDR "is treated like generation" in the CAISO's tariff rules.[37] FERC further determined in Order 745 that DR can act as an alternate for generation and is entitled to equal compensation under certain conditions.[38]

In other words, DR participating in wholesale markets substitutes for generation. FERC has ordered compensation for such resources equal to that received by generation resources. Utility costs associated with generation facilities and procurement are

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[35] 2009 CAISO Annual Report, pp. 18-19.
[36] D.10-12-036, Ordering Paragraph 1, p. 7.
[37] *Order Conditionally Accepting Tariff Changes and Directing Compliance Filing*, 132 FERC ¶ 61,045, ER10-765-000, July 15, 2010, paragraph 24.
[38] *Demand Response Compensation in Organized Wholesale Electric Markets*, 134 FERC ¶ 61,187, March 15, 2011, paragraph 47.

recovered through generation rates. It logically follows that costs associated with DR Supply Resource programs must be treated the same way.

Q. Please explain your cost allocation principles for Load Modifying Resources.

A. D.14-03-026 adopted a categorization of certain utility DR programs as Load Modifying Resources.[39] The utility DR programs assigned to Load Modifying Resources include two types: (1) pricing tariffs for bundled utility customers that are intended to incent customers to reduce their energy consumption during peak periods and (2) Load Modifying DR programs that are open to all customers but provide RA credits or other generation-like function, such as peak-shifting. This categorization serves as the basis for the recommended cost allocation principles. Table 2 lists the five IOU DR programs categorized as Load Modifying Resources in D.14-03-026 and represents my understanding about which IOUs offer the programs, which customers are eligible to participate in them, and whether they receive RA credits. As is clear, most of these IOU programs apply to bundled customers only.

[39] D.14-03-026, Table 2, p. 21.

Table 2 Load Modifying Resources As Proposed in D.14-03-026 -- Customer Eligibility and RA Credits			
DR Program	**IOU**	**Eligibility**	**RA Credit**[40]
Critical Peak Pricing (CPP)	SCE, SDG&E	Bundled only	Yes
Time of Use (TOU) Rates	PG&E, SCE, SDG&E	Bundled only	–
Permanent Load Shifting (PLS)	PG&E, SCE, SDG&E	All	–
Real Time Pricing (RTP)	SCE	Bundled only	–
Peak Time Rebate (PTR)	SDG&E	Bundled only	Yes

Q. Please explain the cost allocation principle that applies to utility pricing tariffs.

A. Pricing tariffs include a broad range of tariffs that are available and applicable solely to bundled utility customers and are intended to encourage energy conservation during peak hours or hours with high market prices. Many of the tariffs are default tariffs under which the utilities sell electricity to their bundled customers. As noted above, in Table 2 of D.14-03-026, the Commission proposed that all TOU rates, as well as real-time pricing ("RTP") and peak-time rebate ("PTR") tariffs, be included in the Load Modifying Resources category.[41] Dynamic pricing tariffs offered by the utilities also fit into this category. The Commission recently determined in D.12-12-004 that the costs associated

[40] The IOUs' DR programs receiving RA credits are listed in reports posted on the CPUC web site at the following link; the other programs are not listed in these reports as receiving RA credits and I was unable to determine if those programs are used to reduce the RA load forecast: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm

[41] D.14-03-026, Table 2, p. 21.

with dynamic pricing tariffs should be recovered solely from bundled customers through generation rates, and provided a detailed rationale for that determination:

> We are persuaded by the arguments of the Direct Access Parties that requiring the customers of CCAs and ESPs, who cannot enroll in SDG&E's dynamic pricing tariffs, to pay the costs of implementing those tariffs, is not consistent with cost causation principles, and would not be reasonable. … Further, even if customers could move easily back and forth between different service providers, a customer is not able to take advantage of SDG&E's dynamic pricing while taking commodity service from any provider other than SDG&E. As a result, charging customers of other LSEs to implement these tariffs, or even charging them for the incremental costs of implementing or maintaining tools supporting these tariffs (such Web sites or additional customer service), would be charging them for costs that they do not incur and that do not significantly benefit them.
>
> When or if customers choose to move back to SDG&E bundled service, they would bear their share of the costs adopted in this proceeding under their bundled rates. The possibility that customers of other LSEs could use Web-based tools supported by dynamic pricing implementation funds in their decision-making, or could switch to bundled service and dynamic rates in the future, is not sufficient to convince us that the costs of developing and implementing these tools should be collected from those customers. … This conclusion is similar to the Commission's conclusion in D.02-11-022. For these reasons, we require that the ***costs of SDG&E's dynamic pricing decision be recovered from all bundled customers through generation rather than distribution rates***. (emphasis added)[42]

[42] D.12-12-004, pp. 52-53.

The same rationale applies to any utility pricing tariff used solely for sales of electricity to bundled customers. These costs relate to provision of electricity to bundled customers and must be recovered solely from those customers. Nevertheless, costs associated with all the IOUs' pricing tariffs other than the SDG&E dynamic pricing addressed in D.12-12-004 continue to be recovered through distribution rates. This inconsistency must be rectified by having the costs associated with all pricing tariffs categorized as Load Modifying Resources recovered in the same manner as SDG&E's dynamic pricing tariff – through generation rates.

Q. Please explain the cost allocation principle that applies to Load Modifying Resources that are open to participation by all customers, but provide RA credits or other generation-like functions.

A. This principle is based on the same rationale used for Supply Resources: the DR program is performing a generation function and therefore the associated costs must be recovered from generation rates. RA credit is conferred only for resources that can meet an LSE's RA requirements – these are typically generation resources. Thus, if the DR resource receives RA credits, it is substituting for generation and performing a generation function. If the Load Modifying Resource program receives RA credit pursuant to the applicable Commission rules at the time, the utility running the Load Modifying program would therefore retain the RA credits for meeting its own RA requirements. An example of a type of utility program that does not receive RA credit, but performs a generation-like function is Permanent Load Shifting ("PLS"),[43] which offers incentives for storing electricity during off-peak and using it to support load on peak.[44] The costs of this program should therefore be allocated to generation.

Q. Are there utility DR Programs that are Load Modifying Resources for which the costs should be recovered through distribution rates that are paid for by all customers, including direct access customers?

A. I am aware of no such current utility DR programs. As noted above, I believe only one Load Modifying Resource DR program listed in Table 2 of D.14-03-026 is open to all customers, Permanent Load Shifting, and that program results in peak-shifting, thereby avoiding construction or use of other peaking resources. I see this as a generation-related function and the associated costs should be recovered through generation rates. In fact, both the Supply Resources and Load Modifying Resources categorized in D.14-03-026 provide generation-related services or are available only to bundled customers. As such, the costs of both types of resources should be recovered solely from bundled customers through the IOUs' generation rates. If and only if the utilities develop a DR program in the future that is designed solely to reduce the use of the distribution system and which both allows and results in participation by retail choice customers should the costs be recovered through distribution rates.

III. UTILITY-CENTRIC MODEL

Q. Does California have a utility-centric model for DR?

[43] D.14-03-026, Table 2, p. 21.
[44] A uniform PLS program for the three IOUs was approved by the Commission by letter from Energy Division on September 5, 2013.

A. Yes. The IOUs dominate in offerings of both DR Supply and Load Modifying Resources. Participation in the market by third-party DR Providers is almost entirely dictated by the extent to which the IOU has offered the opportunity for them to bid to provide AMP contracts or aggregate customers for certain IOU DR programs. Of the many DR programs offered by the IOUs, Table 3 shows which utility DR programs I understand allow participation by third-party DR Providers. As reported by the CAISO, participation by independent, third-party DR Providers outside of the IOU DR programs is practically nil.[45]

Table 3
IOU DR Programs Allowing Participation by Third-Party DR Providers

DR Program	PG&E	SCE	SDG&E
Base Interruptible Program (BIP)	✓	✓	✓
Capacity Bidding Program (CBP)	✓	✓	✓
Demand Bidding Program (DBP		✓	
Aggregator Managed Portfolio (AMP)	✓	✓	
Summer Saver Program[46]			✓

Q. What is the participation of the IOUs' DR programs in California's energy markets?

[45] CAISO's 2013 Annual Report, *loc. cit.*, p. 32: "Independent curtailment service providers offer demand response by participating in utility sponsored programs, as do other non-utility entities." Also: "Almost all of California's current demand response consists of load management programs operated by the state's three investor-owned utilities.

[46] According to the information available on this program from SDG&E's web site, this SDG&E DR program is administered by Comverge.

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A. As shown in Table 4, participation in the CAISO's wholesale energy markets of DR through the IOUs' programs has not shown significant progress since 2007, despite the substantial funding authorized by the Commission. The CAISO reported in its 2013 Market Report that DR programs operated by the three IOUs meet "about 5%" of system RA requirements.[47] This number has not changed over the years.[48] I recognize that the funding authorized by the Commission and shown in Table 1 above includes DR programs not bid into the CAISO's markets or responsive to system emergencies or high market prices. Nonetheless, the level of authorized funding has not translated into significant progress in DR wholesale market participation.

Table 4
CAISO Market Report on IOU DR Programs (MW)[49]

IOU DR Program Type	2007 Enrolled	2008 Enrolled	2009 Enrolled	2010 Estimated	2011 Estimated	2012 Estimated	2013 Estimated
Price Responsive[50]	999	1,287	1,095	589	814	1,420	1,164
Reliability Based[51]	1,726	2.007	2,172	1,544	1,428	1,010	1,016
TOTAL	2,725	3,294	3,267	2,134	2,270	2,430	2,180

[47] CAISO, *2013 Annual Report on Market Issues and Performance*, April 2014, p. 32.

[48] The CAISO has reported this number in its annual market reports from 2009 to 2013. Except for 2010 for which 4.5% was reported, the other years were all around 5%. The CAISO's annual market reports are available at: http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx

[49] 2007 data from CAISO 2011 Annual Report on Market Issues and Performance, April 2012, Table 1.3, p. 30; 2008 data from 2012 report, April 2013, Table 1.3, p.32; remaining data from 2013 report, April 2014, Table 1.3, p. 34.

[50] The CAISO's 2013 report (p. 33) states that price-responsive program includes day-ahead and day-of programs; some are dispatched in response to expected high market prices.

[51] The CAISO's 2013 report (p. 33) states that "reliability-based" programs are primarily large retail customers under interruptible tariffs and air conditioning cycling programs; the programs are "primarily triggered when the ISO declares a system reliability threat."

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Q. If the Commission decides to move away from the utility-centric model, how could it do so?

A. First and most important, the Commission should adopt the recommended cost allocation principles set forth above, which will encourage third-party participation in the DR market and ensure competitive neutrality. Second, the Commission should finalize the determination of how all DR programs will be counted for RA purposes to eliminate those uncertainties. Finally, to the maximum extent possible, all IOU DR programs should be competitively procured. The Demand Response Auction Mechanism ("DRAM") proposed by Staff in this proceeding is one approach that may be worthwhile, but, at this point in time, it is not clear how an auction would improve upon the utility-run RFOs. For example, SCE and PG&E have run RFOs for their AMP programs and a similar approach could be used to procure a broader array of DR services from third-party DR Providers.

Q. Could the IOUs continue to offer DR services to consumers?

A. As explained, most of the DR Load Modifying Resources are, in fact, utility pricing tariffs for sales of electricity to their bundled customers. The IOUs likely will continue to offer service under those tariffs. For all other utility-based DR programs, the Commission should maximize competitive procurement for these services to ensure a continued and meaningful role for third-party DR Providers in the California DR market.

IV. BACK-UP GENERATORS

Q. The Revised Scoping Memo issued on April 2, 2014 seeks proposals for methods to exclude demand reduction provided through the use of Back-Up Generators ("BUGs").[52] Do you have comments on that request?

A. Yes. DACC and AReM oppose excluding demand reduction provided from resources that use BUGs. In establishing this DR rulemaking, the Commission explained that it:

> … intends to build upon the body of work completed to date and retool demand response to align with the grid's needs and ***enhance the role of demand response*** in our energy policy. (emphasis added)[53]

As DACC and AReM noted in their response to questions on foundational issues, if the Commission's goal is to maximize DR resources, a prohibition on the use of BUGs will run counter to that goal by reducing participation of DR in CAISO markets.[54] Specifically, DACC members are concerned that such a prohibition would hamper the economic development of newer back-up technologies, such as fuel cells, batteries, and other emerging storage technologies. Even the use of fossil fuels for back-up generation (including diesel) in certain instances, while creating emissions that would be avoided if the DR resource was foregoing all consumption of power, may still be preferable to the construction of new larger-scale peaking facilities. DACC and AReM urged the Commission to explore the use of BUGs to provide DR Supply Resources and determine the types of units, fuels, or operation that could be used and still allow the resource to qualify as a RA resource.

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[52] Revised Scoping Memo, *loc. cit.*, Attachment A, p. 7.
[53] R.13-09-011, p. 15.
[54] *Response of the Direct Access Customer Coalition and Alliance for Retail Energy Markets to Questions on Foundational Issues*, R.13-09-011, December 13, 2013, pp. 11-12.

DACC and AReM also reiterate their proposal to address the following options in this proceeding for determining whether DR Supply Resources supported by BUGs may qualify as an RA resource:[55]

- Consider the extent to which the resource is subject to and meets all federal, California Air Resources Board ("CARB") and local air quality management districts' emission standards. For example, if back-up generation meets the low emission standards of the local air quality management district for stationary sources, then the unit could be approved for use as an RA resource.
- Allow back-up generation to be bid into CAISO markets as a DR resource (and to receive RA credit) when the unit conducts its required testing.
- Work with CARB to define the acceptable uses of back-up generation for providing DR Supply Resources under the plan for reducing GHG pursuant to Assembly Bill 32.
- Work with local air quality management districts to consider acceptable conditions for waivers of emission requirements to use back-up generation for providing DR Supply Resources in CAISO markets. For example, back-up generators can be operated in case of emergencies under most air quality district rules. Therefore, if a request for DR resources is considered an "emergency," the restriction on operations should be removed.

In summary, DACC and AReM respectfully request that the Commission devote some time in this proceeding to addressing the use of BUGs to enhance, not hinder, DR expansion.

[55] *Ibid,* p. 12.

V. DEMAND RESPONSE AUCTION MECHANISM (DRAM)

Q. The Staff has proposed that the IOUs be required to procure DR Supply Resources competitively on behalf of their own load through an auction mechanism.[56] What are your comments on this proposal?

A. I have no comments at this time on the DRAM proposal for utility procurement of DR, but reserve the right to file comments on reply.

Q. Should non-utility LSEs be required to procure RA capacity through the DRAM?[57]

A. I do not believe that the Commission has jurisdiction to require ESPs to procure through the DRAM. Specifically, PU Code Section 394(f) states as follows:

> Nothing in this part authorizes the commission to regulate the rates or terms and conditions of service offered by electric service providers.[58]

The Commission has interpreted this statutory provision as prohibiting its ability to review or approve procurement by the ESPs.[59] Accordingly, I believe the Commission is not permitted to order ESPs to procure from specific procurement platforms nor does it have jurisdiction over the ESPs' supply portfolios.

Q. Does this conclude your testimony?

A. Yes, it does.

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[56] *Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revised Schedule for Phase Two, and Providing Guidance for Testimony and Hearings*, R.13-09-011, April 2, 2014, Attachment B.
[57] *Ibid*, Attachment A, p. 4.
[58] PU Code Section 394(f).
[59] See. D.11-01-026, p. 23: "… the Commission's long-standing position, consistent with § 394(f), that it does not review or approve the procurement contracts of ESPs, whether for conventional generation or RPS-eligible resources." See also, D.05-11-025, pp. 12-13: "ESPs and CCAs each are subject to separate and distinct legal and regulatory requirements. … This Commission has less overall control over how ESPs and CCAs operate than we do over how utilities operate."

ATTACHMENT A: WITNESS QUALIFICATIONS

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EXPERIENCE

1/02 – Today 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, California State University, Cargill, Constellation NewEnergy, ConEdison Solutions, Direct Access Customer Coalition, Direct Energy, Energy Curtailment Specialists, Noble Americas Energy Solutions, Retail Energy Supply Association, Safeway, Stanford University, University of California, and Wal-Mart. Activities include:

- Advocating proposals regarding resource adequacy and capacity markets before CPUC and CAISO.
- Advocating competitively-neutral Smart Grid and greenhouse gas policies.
- Advising on demand response policies at the CPUC and CAISO.
- 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 electricity and gas 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 SINCE 1997

CPUC

R.12-03-014, Testimony filed June 25, 2012 in Long-Term Procurement Proceeding, Track 1, on behalf of the Alliance for Retail Energy Markets, Direct Access Customer Coalition and Marin Energy Authority (now Marin Clean Energy).

A.11-11-017, Testimony filed May 16, 2012 in Pacific Gas and Electric Company's Smart Grid Pilots proceeding, on behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition.

A.08-06-001, A.08-06-002, A.08-06-003, Testimony filed November 24, 2008 on the investor-owned utilities' 2009-2011 Demand Response Programs, on behalf of the Alliance for Retail Energy Markets.

R.06-02-013, Testimony filed March 2, 2007 in the Long-Term Procurement Proceeding, Phase 2, on behalf of the Alliance for Retail Energy Markets.

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 (now Shell Energy).

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.