BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	Rulemaking 13-09-011

OPENING BRIEF OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION ON PHASE TWO ISSUES OF COST ALLOCATION AND BACK-UP GENERATION AND THE PHASE THREE ISSUE REGARDING THE DEMAND RESPONSE AUCTION MECHANISM PILOT

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August 25, 2014

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Pursuant to Rule 13.11 of the California Public Utilities Commission's (Commission's) Rules of Practice and Procedure and Administrative Law Judge Hymes' email Ruling of August 13, 2014, the California Large Energy Consumers Association[1] (CLECA) submits this opening brief.

I. INTRODUCTION

A paradigm shift for demand response is underway, with operational bifurcation to "occur beginning with the 2017 demand response program year."[2] The Commission's intended result is growth and increased prioritization of demand response. These overarching goals should inform the consideration of the issues related to back-up generation, cost recovery policy and whether the proposed Demand

1 The California Large Energy Consumers Association is an organization of large, high load factor industrial electric customers of Southern California Edison Company and Pacific Gas and Electric Company. CLECA member companies are in the cement, steel, industrial gas, beverage, pipeline and mineral industries. CLECA has been an active participant in Commission regulatory proceedings and Commission-authorized Demand Response Programs since 1987.

2 D.14-03-026,at 1.

Response Auction Mechanism (DRAM) should be a preferred means of procurement. The litigation outcome for these issues should not lead to diminished demand response, either during the transition to bifurcation or later. Accordingly, the Commission should conclude:

- Existing federal, state and local air quality regulation of back-up generation suffices to address air quality concerns; at this point, the Commission need not and should not jeopardize participation in demand response with duplicative or possibly conflicting, ultra vires regulations on back-up generation, particularly without a robust record.
- Current cost recovery policy is fair and current allocations should remain in place for 2015-2016; the DRAM Pilot costs should be allocated on a distribution basis to all customers as the demand response will provide system benefits to all customers, and later, local and flexible reliability benefits to all customers; depending on the programs proposed for the next demand response cycle, cost recovery and allocation may be revisited, but the existing cost recovery policy should not be changed.
- It is premature to establish the DRAM as a preferred mechanism for supply resource demand response; the lessons learned from the DRAM Pilot should inform the determination on whether or not DRAM should be a preferred mechanism for procurement. Accordingly, this determination should be made during the Settlement Agreement's proposed mid-course review for the proposed 2017-2019 program cycle based on facts that will become known over the pilot period and during the first part of that next program cycle.

These conclusions are supported by record evidence, reasonable and lawful. They will promote the growth and increased prioritization of demand response and should be adopted.

II. PHASE TWO ISSUES: BACK-UP GENERATION AND COST ALLOCATION

A. Back-Up Generation (BUG)

In late 2011, the Commission issued a policy statement on back-up generation used by demand response providers and deferred the details of implementation to a subsequent proceeding.[3] The details for implementation of this policy statement have not yet been developed.[4] The Commission should thus first find that there have been no violations of its policy pronouncement because it has not yet been implemented. The Commission should further reject ORA's recommendation for "financial consequences for Demand Response Providers … for either knowingly allowing or ignoring customer's use of BUGs in providing DR."[5] There have been no violations, and there is no call for financial consequences at this point.

The difficulties in developing the details are numerous and include a continued lack of record data and an apparent lack of a cost-effective means of obtaining the data.[6] These difficulties are discussed below; they arise, in part, due to a threshold

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3 *See* D.11-10-003, at 30 ("our policy statement only applies to fossil-fueled emergency back-up generation. … We will require the IOUs work with Energy Division to identify data on how customers intend to use BUGs, and to identify the amount of DR provided by BUGs when enrolling new customers in the DR programs or renewing DR contracts. ***We will defer the details on the process evaluation to the IOUs' 2012-2014 DR applications***. …"); *see also* Ex. PG&E-01, at 7-3; *see also* Ex. SCE-01, at 47-48.

4 *See* Ex. CLE-02, CLECA Reply Testimony, at 4 ("There is no rule or policy currently in force for which the utilities can be found in violation."); *see also* Ex. SCE-01, at 47 ("There are no compliance obligations related to whether a DR program that includes participants that use BUGs should count towards RA obligations"); *see also* Ex. PGE-03, at 3-2 ("the Commission has not adopted any changes … there is no Commission-mandated program for oversight of fossil-fueled BUG"); *see also* Joint Response of EnerNOC, Inc., Johnson Controls, Inc., and Comverge, Inc., ("Joint DR Parties") on Phase 2 Foundational Questions (Joint DR Parties Response), dated Dec. 13, 2013, at 11.

5 Ex. ORA-01, Opening Testimony of the Office of Ratepayer Advocates, at 16.

6 *See* SCE Responses to Phase 2 Foundational Questions, dated Dec. 13, 2013, at A-9; *see also* PG&E Responses to Phase 2 Foundational Questions, dated Dec. 13, 2013, at 17 ("PG&E has very little information regarding customer use of BUGs during DR events … PG&E does not collect data on BUG usage in DR programs.").

issue: the lack of jurisdiction. Jurisdiction over back-up generation is held by federal, state and local air quality agencies, and not the Commission.

1. Jurisdiction Lies With Air Quality Agencies

Federal, state and local air quality agencies have clear jurisdiction over back-up generation; the Commission does not. Federal regulations specifically allow limited use of emergency fossil-fueled back-up generation in connection with demand response.[7] As EnerNOC/Comverge explained, the Environmental Protection Agency regulates this use and restricts it to operating a maximum of 100 hours per year out of 8760:

> for a BUG to qualify as an emergency generator, it must be dispatched in response to a system operator's energy emergency alert level 2 (EEA)-2 declaration or where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency. EPA defines these conditions as emergency DR and allows up to 100 hours per calendar year of this use including testing and maintenance. A Stage 2 Emergency is when CAISO predicts its operating reserve margin to go below 5%. The CAISO has not had a Stage 2 Emergency since 2006, where there was one occurrence. The largest incidence of emergency alerts occurred during the Energy Crisis in 2000 and 2001. Since that time, Stage 2 Emergencies have been infrequent and are not likely to exceed the 100 hours per year for emergency dispatch contained in the EPA rules.
>
> In addition, EPA allows up to 50 of the 100 hours for what EPA calls "non-emergency situations" but what should be called "transmission or distribution-level emergencies." This use is limited to dispatches that are intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage

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[7] *See* Reply of CLECA to Responses to Phase Two Foundational Questions, dated Dec. 31, 2013, at 8; *see also* Joint Reply of Enernoc Inc., and Comverge, Inc., to Responses to Phase Two Foundational Questions (Joint DR Parties Response), dated Dec. 31, 2013, at 10.

> collapse or line overloads that could lead to the interruption of power supply in a local area or region.[8]

Recently, the EPA explained its reasoning for allowing the limited use of emergency back-up generation in response to local disturbances:

> The conditions under which an engine could operate needed to encompass the varying emergency operating procedures for local systems all over the U.S. … Through consultation with the local transmission and distribution operators, the EPA developed criteria for the conditions under which the engines could be used for up to 50 hours per year in local grid emergency situations. …
>
> [EPA agrees that] a provision for limited operation of emergency engines when there are conditions that could lead to a blackout for the local area is appropriate. … Dating back to the original RICE NESHAP in 2004, the EPA has a long history of regulating emergency engines … and establishing different standards for emergency engines. The EPA has done so based on significant considerations, including, for area sources of HAP, the high-cost of add-on controls, given the amount of time emergency engines operate, concerns that emergency engines may not operate long enough for a catalyst to reach the temperature needed to reduce emissions, the impracticality of operating the engine to test emissions when the engines operate so infrequently and at unpredictable times, the need for these engines to be operated with little time for startup and the possibility that add-on controls could inhibit the ability for emergency engines to accomplish their time-critical functions.[9]

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8 *See* Joint DR Parties Response, at 13-14.

9 US EPA Memorandum, Response to Public Comments on Notice of Reconsideration of National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Internal Combustion Engines("Response to Comments Document"), dated June 16, 2014, at 14 (available online at: http://www.epa.gov/ttn/atw/icengines/docs/20140801responsetocomments.pdf).

EnerNOC/Comverge noted, "Since BUGs are considered emergency resources, the failure of a unit to operate during an emergency could be catastrophic."[10] The Commission's policy should not conflict with these federal air quality regulations; nor should the Commission engage in contradictory regulation of the use of back-up generation permitted by state and local air quality agencies in connection with demand response. As SCE explained, the local air quality agencies have authority over emissions from back-up generation.

> Air pollutants emitted from the use of BUG are governed by California's air pollution control districts (APCDs) and air quality management districts (AQMDs). These agencies have been granted legislative authority to exercise responsibility for comprehensive air pollution control within a particular region. [11]

The Commission's jurisdiction, while broad, is not unlimited. It is founded in the state Constitution[12] and Public Utilities Code Section 701.[13] When Commission regulation over public utilities conflicted with air quality district regulation of emissions, the court has been clear that the delegation of regulatory authority over air quality issues is to the air quality agency, not the Commission:

> We conclude that the Legislature has established one statutory scheme for the general regulation of public utilities, another for the general regulation of air pollution. … **Here the Legislature has itself enacted specific emission control standards and has erected a comprehensive statutory structure for**

[10] Joint Reply of EnerNOC, Inc., and Comverge, Inc. to Responses to Phase Two Foundational Questions (Joint Reply Comments), dated Dec. 31, 2013, at 8.

[11] Ex. SCE-01, at 48. *See also* Ex. PGE-01, at 7-5 ("the Commission should consider the jurisdictional aspects of prohibiting fossil-fueled BUG providing DR … it is not clear that the Commission has the authority to prohibit the use of fossil-fueled BUG for Supply Resource DR because once the Commission allows retail load to be used for Supply Resource DR, the Supply Resource DR's participation in the CAISO wholesale market would be pursuant to CAISO rules, which are subject to the Federal Energy Regulatory Commission's jurisdiction").

[12] *See* Cal. Const., Art. XII, §2, 4, 6.

[13] P.U. Code §701.

the adoption of further controls. These controls without doubt apply to public utilities. **The Legislature has delegated enforcement of these emission controls to air pollution control districts**. … the commission must share its jurisdiction over utilities regulation where that jurisdiction is made concurrent by another (especially a later) legislative enactment.[14]

Indeed, PG&E rightly queried whether the California Air Resources Board may be "better suited to adopt rules" on back-up generation.[15] EnerNOC/Comverge agreed that regulation "should be left to the appropriate regulatory authorities with the requisite jurisdiction and competence regarding emissions and air quality matters."[16] As Dr. Barkovich stated, "It is not the CPUC's jurisdictional responsibility to enforce air quality regulation at either the state or federal level."[17]

This Commission should recognize regulation by federal, state and local air quality agencies and the permitted uses of back-up generation by those agencies and defer the regulation of back-up generation to those agencies entrusted with air quality.[18] A revision of the 2011 policy statement is warranted to ensure consistency with federal, state and local air quality regulations and for administrative efficiency. The Commission has already acknowledged it should use a definition of emergency back-up generation consistent with those of federal, state or local air quality agencies.[19] It should also permit use of fossil-fueled, emergency back-up generation by customers as allowed by

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14 *Orange County Air Pollution Control Dist. v. Public Util. Com*. (1971) 4 Cal. 3d 945, 953; 95 Cal.Rptr. 17.

15 *See* Response of Pacific Gas & Electric Company to Joint Assigned Commissioner and Administrative Law Judge Ruling and Scoping Memo, dated Dec. 13, 2013, at 17-18.

16 Joint Reply Comments, at 10.

17 Ex. CLE-01, at 43.

18 See Ex. SCE-02, at 17.

19 *See* D.11-10-003, at 30 ("definition of emergency BUG should be consistent with the definition by the US Environmental Protection Agency (USEPA) or state or local air regulation Agencies.")

federal, state, and local air quality regulations for participation in demand response. Given its nebulous authority, the Commission should certainly not devise or implement regulations that conflict with those established by air quality agencies.

Further, the Commission should not needlessly minimize either potential demand response or existing demand response by excluding a customer's response that, due to safety requirements, may be associated in part with emergency fossil-fueled back-up generation. Consider a customer with a 300 kW emergency back-up generator to meet safety requirements that could offer 10 MW of demand response.[20] It would be illogical to disallow the customer's potential demand response because of that emergency back-up generation. PG&E suggested that the Commission consider the impact of eliminating DR supported by back-up generation, the impact of the alternative procurement (e.g., gas-fired peakers) and the costs and benefits of implementing the current policy statement.[21] For all of these reasons, the 2011 policy statement should be revised. If the policy statement is not revised, developing the necessary details to implement the 2011 policy statement will be difficult and is not supported by the current record.

2. Record and Data Issues Continue to Prevent Determination of Implementation Details for the 2011 Policy Statement

The current record lacks the data necessary to implement the policy statement and a cost-effective path for establishing the record data is not clear. CLECA agrees with PG&E's recommended development of a "robust record on the use of fossil-fueled

[20] *See, e.g.,* Ex. CLE-02, CLECA Reply Testimony at 4.
[21] *See* Response of Pacific Gas & Electric Company to Joint Assigned Commissioner and Administrative Law Judge Ruling and Scoping Memo, dated Dec. 13, 2013, at 17-18.

BUG for DR" prior to a final determination on policy or implementation.[22] It is evident, however, that the utilities are not the appropriate entities to gather the data.[23] The prior record in the proceeding where the Commission adopted its policy statement also lacked data.[24] It is difficult to see how such a record can be developed without imposing significant metering costs, or data gathering costs, or eroding customer willingness to participate, or all of the above.[25]

Moreover, in terms of reporting, the Commission should not increase the reporting burden on customers beyond the requirements instituted by air quality regulators. The Environmental Protection Agency will require reporting by March 31, 2016 of calendar year 2015 operations of certain back-up generators for "emergency demand response and local reliability operations".[26] At the state level, the California Air Resources Board collects data on use of back-up generation.[27] At the local level, the regulation by the local air quality agencies was explained by SCE:

> The Public Utilities (P.U.) Code includes a process for IOUs to provide information to the APCDs and AQMDs to allow them to enforce BUG rules. Pursuant to PU Code Section 743.3, on a monthly basis, SCE provides to the

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[22] Ex. PGE-01, at 7-4.

[23] Ex. PGE-01, at 7-3 ("because the data are likely under the jurisdiction of CARB, the IOUs may not have the authority to collect it").

[24] D.11-10-003, at Conclusion of Law 4 ("There is not sufficient information in the record to adopt specific RA rules regarding fossil-fuel back-up generation.").

[25] *See* Ex. PGE-01, at 7-4 to 7-5 ("it is not clear what purpose would be served by requiring sub-metering for BUG, and it is not clear that the additional cost and administrative burden would be worth the benefits… applying this [submetering] requirement only to DR customers would likely create a disincentive to participate proportional to the added cost and administrative burden.")

[26] US EPA Response to Public Comments On Notice of Reconsideration of National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Internal Combustion Engines, June 16, 2014, at 6 (available at: http://www.epa.gov/ttn/atw/icengines/docs/20140801responsetocomments.pdf). CLECA understands that the EPA Final Rule has been appealed to the DC Circuit Court.

[27] *See* Ex. PGE-01, at 7-3.

APCDs and AQMDs in its territory a confidential list of SCE customers participating in an interruptible program, which enables the APCD/AQMD to cross-reference its list of BUG permits with customers participating in the interruptible program.[28]

These federal, state and local air quality regulations render any new Commission requirement to collect data redundant and administratively inefficient.

B. Cost Recovery Policy

There are two issues associated with cost recovery policy: cost recovery and cost allocation. The first, cost recovery, is who pays the costs, either just bundled customers or bundled and non-bundled customers; this should be determined based on cost-causation (who causes the costs) and a corollary beneficiary principle (who benefits). Critically, in light of its goals for demand response, the Commission should ensure that its determination on cost recovery policy does not limit DA and CCA customers' ability to choose to participate in demand response programs, including utility programs. The policy should ensure recovery of costs at a minimum from all customers eligible to participate in the programs in question.[29] Regardless of eligibility, however, if a program benefits all customers, then all customers, bundled and non-bundled, should pay for the costs.

The second issue, allocation, is how the costs are allocated to those customers paying them; generally, this has been determined by function (generation or distribution) or a combination of functions (e.g., equal percent of revenues).[30] In light of the new

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28 Ex. SCE-01, at 48.

29 *See, e.g.*, Ex. CLE-02, at 12; *see also* Ex. MCE-01, at 6.

30 *See, e.g.*, D.97-08-056 (establishing functional cost allocation principles); *see also* Ex. CLE-02, at 12 (explaining the error in "the apparent presumption that the costs are also allocated on a distribution. This is not necessarily the case. Recovery in delivery charges

bifurcation paradigm and the new roles and expectations for demand response, the appropriate basis for allocation may be changing.

1. Current Cost Recovery Should Be Maintained Through 2016

The utilities' current cost recovery varies minimally, with most demand response program costs being recovered on a distribution basis from all customers, including bundled and non-bundled customers.[31] The exceptions are SCE and SDG&E dynamic pricing programs, for which eligibility and cost recovery is limited to bundled customers, and PG&E's Aggregator Managed Programs, whose costs are allocated as generation costs but recovered from all customers.[32]

CLECA has long supported DR-related cost recovery from all customers since all customers receive enhanced reliability and lower market clearing prices from DR and since customers of all LSEs are able to participate in IOU DR programs other than pricing programs. CLECA has also long supported cost allocation based on the functional nature of the costs. As PG&E explained, a distribution allocation for demand response is appropriate because "DR programs are customer-service related, as they support programs that enable customers to reduce their electricity costs by reducing peak demands."[33]

The current cost recovery and allocation will be continued during the 2015-2016 bridge funding period.[34] The pending Settlement Agreement proposes to fund the costs

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means that non-bundled customers are also charged. However, it does not necessarily mean that costs are allocated in any particular way.").

[31] *See* Workshop Report, at 4.

[32] *Id*.

[33] Ex. PGE-01, at 8-3.

[34] *See, generally*, D.14-05-025 (adopting bridge funding budgets and no significant programmatic changes for the bridge funding period of 2015-2016).

of the DRAM Pilot with the current authorized bridge funding.[35] The DRAM Pilot cost recovery should accordingly comply with the current cost recovery policy, which allocates the majority of costs on a distribution basis and recovers them from all customers. This would fairly recover the costs, as the demand response procured through the DRAM Pilot will provide system benefits to all customers, and later, local and flexible reliability benefits to all customers. The first DRAM Pilot will be for system RA capacity from third-party procurement of demand response; the second pilot will be for system, local and flexible RA tags.[36] As SCE stated, “To the extent utilities use third-party procurement of DR resources to meet system needs, the costs would be allocated to all benefitting customers.”[37] PG&E also states, “when a customer is eligible for an IOU’s DR programs, the customer should help pay the costs of the DR Programs.”[38] Accordingly, the DRAM Pilot costs should be recovered from all customers and allocated on a distribution basis.

For the post-bridge funding period, the demand response paradigm is changing, and it may be appropriate to review cost allocation in the context of the next program cycle and under the new bifurcation paradigm. This review, however, and the ultimate determination should be informed by the actual, specific programs and associated costs to be submitted in November 2015 for the next DR program cycle; it should not be prejudged now.[39]

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35 *See* Settlement Agreement, at 28-29.
36 *See* Settlement Agreement, at 27.
37 Ex. SCE-01, at 41.
38 Ex. PGE-02, at 4-3.
39 *See* Ex. SCE-01, at 45.

2. Do Not Presume Function and Set Allocation Based on Bifurcation

The Commission should reject the DACC/AReM proposal to presume all supply resource demand response is functionally equivalent to generation and allocate all its costs as generation, recovering those costs only from bundled customers.[40] First, this proposal would not ensure contributions from all benefitting customers. As Dr. Barkovich explained, programs with products offered into the CAISO market enhance reliability for all customers and may also serve to reduce the market clearing price, reducing costs for all customers; accordingly, their costs should be allocated to all customers.[41] SCE witness Silsbee noted "utility DR programs have a core objective to reshape the load that customers placed on the wholesale market to provide a benefit to all customers."[42]

Second, it wrongly presumes that a supply resource demand response program would function only as generation. As SCE witness Silsbee explained in the workshop, an allocation based purely on a single function may no longer work. "Allocating costs based on the function of a DR program may be impractical because programs serve multiple functions (e.g., reducing generation needs, alleviating transmission congestion, etc.)."[43] Indeed, Dr. Barkovich testified, "Costs could be allocated on the basis of some

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40 *See* Workshop Report, at 6.

41 *See* Ex. CLE-01, at 44 and at 45 ("these [supply resource] programs will expand the offers in those markets and have the potential to reduce market clearing prices paid to serve all customers. … If these programs are offered into CAISO markets and reduce market clearing prices for load, why should only bundled customers pay for them"); *see also* Ex. PGE-02, at 4-6 ("This lower market clearing price benefits all customers, including customers who are not participating in DR programs").

42 Ex. SCE-02, at 9.

43 Workshop Report, at 8.

combination of generation and distribution costs with ESP and CCA generation costs imputed, as is done for other allocations."[44] Mr. Silsbee explained,

> The objective of influencing customer usage applies regardless of whether DR is dispatched during periods of high prices or to meet generation, transmission or distribution level scarcity or operational needs. Simply because DR is dispatched in a manner integrated with CAISO markets does not make DR a generation function asset. There are numerous trade-offs between generation, transmission and distribution, so that one functional asset can reduce reliance on another asset class.[45]

ORA suggests costs be "allocated to all customers using calculation method that reflects total revenues."[46] According to ORA, this would be fair as DR's "benefits primarily accrue to customers in the form of reduced generation costs and secondarily as reduced transmission and distribution costs" and "all customers benefit from DR programs."[47]

There may be merit to ORA's proposed approach for the 2017-2019 program period. Again, however, the final cost recovery and allocation should be informed by the actual programs themselves.[48] Here, the question is premature, given the absence of facts on the programs and also the data on the current programs to be derived from the DR Potential Study.[49]

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44 Ex. CLE-02, Reply Testimony of Dr. Barbara R. Barkovich on Behalf of the California Large Energy Consumers Association (CLECA Reply Testimony), at 24.
45 Ex. SCE-02, at 9-10.
46 Ex. ORA-02, at 17.
47 Id.
48 *See* Ex. SCE-01, at 45 ("any change in policy should be based on the specific costs for which the utility is seeking recovery and should be specific to each utility funding application. The Commission should refrain from establishing a strict method for DR costs and thereby prejudge all future DR applications.")
49 *See* Settlement Agreement, at 15-17.

Third, the DACC/AReM proposal to simply allocate all supply resource demand response costs as generation fails to address the possibility that, depending on the feasibility of integration into wholesale markets, some programs may be both supply resource and load modifying.[50] Under bifurcation and the Settlement Agreement, supply resource demand response programs get resource adequacy (RA) credit, which would be shared by all load serving entities paying the program's cost. Load modifying demand response programs will provide value based on the reduction of the RA requirement.[51]

Regardless of bifurcation category, however, all load serving entities can and should share in the benefits and costs of demand response programs. As PG&E explains, "DR programs are the means for managing load on the grid, which contributes to maintaining its reliability and stability which benefits everyone using the grid."[52] As Dr. Barkovich described, even if a program does not count for RA credit (i.e., it is a load modifying program), non-utility LSEs can get what used to be known as a capacity credit, allocated on a load share basis.[53] Thus "all LSEs whose customers are paying for DR would receive RA value."[54] The Commission declared in 2009, "We affirm the established principle that DR program capacity credits should be allocated to LSEs in proportion to the funding that their respective customers provide toward DR programs."[55] This process worked fairly for years; it can and should be used again. Supply resource demand response should not be presumed to be functionally

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50 *See* Settlement Agreement, at 22.
51 See Settlement Agreement, at 21-22.
52 Ex. PGE-01, at 8-4.
53 See Ex. CLE-02, at 8-10.
54 Ex. CLE-02, CLECA Reply Testimony, at 9.
55 D.09-06-028, at 27.

generation nor should load modifying demand response be presumed to only be open to bundled customer enrollment. Both categories will continue to benefit all customers; to be fair, all LSEs' customers should pay for demand response.

3. Fairness Dictates Cost Recovery from All Customers

In the absence of a legislative mandate on Electric Service Providers or Community Choice Aggregators to procure demand response, fairness dictates that they share the costs of utility procurement of demand response.[56] SCE explains that "the goal of maintaining competitive neutrality is founded on the underlying principle of equal treatment for all LSEs." Citing Public Utilities Code section 394(f), AReM/DACC witness Mara posits that "the Commission is not permitted to order ESPs to procure from specific procurement platforms nor does it have jurisdiction over the ESPs' supply portfolios."[57] "Because non-utility LSEs have no obligation to procure DR, "the CPUC has no choice but to recover the costs from all customers."[58]

Finally, ORA states that all customers benefit from DR.[59] CLECA agrees and has detailed several of the benefits above; Dr. Barkovich explained the benefits of dynamic pricing for all customers:

> they would benefit from any changes to the system load shape resulting from dynamic pricing by IOUs or other LSEs; a smoother system load shape resulting from dynamic pricing would reduce the overall costs of serving load, for example by reducing ramping requirements, improve the system efficiency and reduce costs to serve all load, not just bundled load.[60]

56 Ex. CLE-02, CLECA Reply Testimony, at 22.
57 Ex. DAC-01, at 27.
58 Ex. SCE-02, at 10; *see also* Ex. CLE-02, CLECA Reply Testimony, at 22-23.
59 *See* Ex. ORA-02, at 17.
60 Ex. CLE-02, at 10.

III. PHASE THREE: WHETHER THE DRAM SHOULD BE A PREFERRED MEANS OF PROCURING SUPPLY RESOURCE DEMAND RESPONSE

The Settling Parties could not come to agreement on:

> the narrowly scoped additional question of whether the DRAM should be a preferred means of procuring Supply DR and if so, with respect to encouraging participation in the DRAM Pilot, the potential interaction of IOU solicitations for Supply Resources with the DRAM Pilot with respect to encouraging participation in the DRAM Pilot and possible limitations on the IOUs' solicitations for Supply Resources…[61]

There are two distinct issues: whether the DRAM should be a preferred procurement mechanism and if so, how that preference should be implemented. It is premature now, in 2014, to determine that the DRAM should be a preferred means of procuring supply resource demand response and establish it as such by limiting other avenues of procurement. This determination should be informed by the experience gained in the DRAM Pilot and the nascent CAISO integration efforts; accordingly, the determination on whether the DRAM should be a preferred mechanism should be made during the proposed mid-cycle review of the 2017-2019 cycle.[62] ORA expressed concern in the workshops that existing demand response participants would not "switch" to engage in the DRAM.[63] This concern is misplaced as the focus should be on growing new demand response with new customers, not cannibalizing existing programs.

Moreover, under the Settlement Agreement's DRAM Pilot, the pilot auctions to be held in 2015 and 2016 will test how this reverse auction procurement mechanism works

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61 Settlement Agreement, at 27.
62 Settlement Agreement, at 30.
63 Workshop Report, at 35.

for demand response.[64] At present, no one can know how the DRAM will actually work for demand response. As Sierra Club witness Binz explained, demand response is different from the Renewable Portfolio Standard (RPS), and the development of the reverse auction mechanism for the RPS occurred under different circumstances and with different goals.[65] As noted in the Workshop Report, the RAM had "a robust supply of providers", but for demand response participants, particularly new participants, it is not known what impact the DRAM criteria may have.[66] The reverse auction mechanism itself may need retooling for demand response – which simply cannot be known until it is actually employed for demand response. As former Commissioner Binz cautioned:

> by prioritizing cost reduction through a mechanism originally designed for multi-MW generation projects able to absorb the risks and costs of a reverse auction process, DRAM could inadvertently limit market participation to larger, more well-established providers and discourage innovative business models and nascent DR technologies.[67]

Despite the commitment by all settling parties to the Pilot's success,[68] it may not work as planned.[69] As the Settling Parties agreed, "the DRAM and wholesale market participation may be significantly impacted by 1) CAISO tariff changes in response to recent and future Court rulings on FERC Order 745, and 2) CAISO requirements for RA product eligibility."[70] It will also take time to solve the issues of integrating demand

64 Settlement Agreement, at 28.
65 *See* Ex. SCL-01, at 15-16; *see also* Ex. PGE-01, at 4-8.
66 *See* Workshop Report, at 33.
67 Ex. SCL-01, at 16.
68 3 Tr. at 141-142 (Settlement Panel: Olivine/Reid).
69 Id. at 142 ("there is too many unknowns and too many things that are going to either be outside of all of our control or variables that are going to come into play in the next few years").
70 Settlement Agreement, at 27-28.

response into the CAISO's markets.[71] Those issues are inextricably linked with the DRAM Pilot.[72] The Commission should allow the time to reach integration solutions, as provided in the Settlement Agreement,[73] prior to determining which procurement mechanisms for supply resources should be preferred. Providing this time for the working group to determine solutions may also allow for both resolution of the court challenges to Order 745 and finalization of CAISO requirements for RA product eligibility. The Commission should avoid combining the unintended consequence of an unsuccessful auction process with limitations on other solicitations as this combination may reduce overall levels of demand response procurement.

A critical aspect of the DRAM Pilot will be its evaluation or the "metrics for success."[74] Before setting a preference for a procurement mechanism, the Commission should be sure that the mechanism itself is successful. The proposed DRAM Pilot enables a feedback loop that should be allowed to work to improve the process and mechanics during the DRAM Pilot and for the first year or two of the next program cycle.

Also, the DRAM Pilot occurs during a transition period to a new bifurcation paradigm, and the Commission should be wary of inadvertently discouraging innovation when the State is trying to incent innovation and grow DR. As PG&E explains,

> [S]tandardizing DR products may not be the most effective method to procure all DR at this stage, given the difficulties to develop standardized products and valuation methods. Opportunities might be lost if cost-effective Supply Resource DR does not meet the requirements of the standardized products that would be

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71 *See* Settlement Agreement, Attachment A, Charter for Supply Resource Demand Response Integration Working Group (listing at pages 2-3 multiple integration issue areas to be addressed by the working group).

72 3 Tr. 139-140 (Settlement Panel: Olivine/Reid)

73 *See* Settlement Agreement, at 17-24.

74 Settlement Agreement, at 28.

> solicited in the DRAM, or if all of the value streams that different types of DR bring to the table are not fully considered in the auction process.[75]

PG&E warned that there had been no showing of the DRAM's effectiveness at procurement[76] (nor could there be, since it has never been used to procure DR). SCE raised an additional concern:

> a variety of hybrid preferred resource configurations, such as solar renewable resources coupled with energy storage, or PLS coupled with DR are beginning to emerge. These configurations do not fit neatly into a program specific definition, and a procurement mechanism such as DRAM that utilizes standard contracts may act to discourage this kind of innovative approach to preferred resources procurement.[77]

As Joint Demand Response Party witness Meehan stated,

> It is possible and even beneficial to maintain several avenues of participation in DR programs for customers with widely varying needs and capabilities. Given the untested nature of the DRAM proposal and other concerns identified in Exhibit JDRP-1, a decision to terminate existing DR programs in the 2016-2018 timeframe would have a chilling effect today on participation in those programs.[78]

At this stage, the Commission should not stifle the potential for growth in the market of different products by limiting avenues for procurement.

The DRAM Pilot is intended to "test the feasibility of procuring Supply Resources for Resource Adequacy with third party direct participation in the CAISO markets through an auction mechanism."[79] It should be allowed to test that feasibility during the pilot period and then inform a subsequent determination on whether or not the

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75 Ex. PGE-01, at 4-5 to 4-6.
76 Id.; *see also* Ex. CLE-02, at 16 ("the DRAM is completely untested.")
77 Ex. SCE-01, at 33; *see also* Ex. SCL-01, at 16.
78 Ex. JDP-04, Phase Two and Phase Three Rebuttal Testimony of Joint Demand Response Parties, at 9.
79 Settlement Agreement, at 24.

mechanism should be a preferred means of procurement.

Given CLECA's position that the DRAM should not and cannot, at this point, be deemed a preferred means of procuring Supply Resource demand response, CLECA does not suggest any limitations on utility solicitations for Supply Resource demand response concurrent with the DRAM Pilot. It should be clear, however, that the timeframe for any proposed limitations that might be considered in the future should be in conjunction with the second DRAM Pilot auction to be held in 2016 for products to be delivered starting in 2017. This is because the Commission has already determined that there are to be no additional operational changes to existing demand response programs in 2015-2016.[80] CLECA reserves the right to respond in its reply brief to other parties' positions on potential limitations as appropriate.

IV. CONCLUSION

For all of the foregoing reasons, the Commission should come to the following conclusions for these litigated issues:

- Existing federal, state and local air quality regulations placed on back-up generation suffice to address air quality concerns; at this point, the Commission need not and should not jeopardize participation in demand response with duplicative or possibly conflicting ultra vires regulations on back-up generation, particularly without a robust record.
- Current cost recovery policy is fair and current allocations should remain in place for 2015-2016; the DRAM Pilot costs should be allocated on distribution basis to all customers as the demand response will provide system benefits to all customers, and later, local and flexible reliability benefits to all customers; depending on the programs proposed for the

[80] *See* D.14-05-025.

next demand response cycle, cost recovery and allocation may be revisited, but the existing cost recovery policy should not be changed.

- It is premature to establish the DRAM as a preferred mechanism for supply resource demand response; the lessons learned from the DRAM Pilot should inform the determination on whether or not DRAM should be a preferred mechanism for procurement. Accordingly, this determination should be made during the next program cycle during the proposed mid-course review based on facts that will become known over the pilot period and during the first part of that next program cycle.

Respectfully submitted,

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August 25, 2014