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

RESPONSE OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION TO PHASE TWO FOUNDATIONAL QUESTIONS

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December 13, 2013

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Pursuant to the November 14, 2013 Commissioner and Administrative Law Judge's Ruling and Scoping Memo, the California Large Energy Consumers Association[1] (CLECA) submits this Response to the Phase Two Foundational Questions.

I. INTRODUCTION

CLECA has participated actively in all proceedings of the California Public Utilities Commission (Commission) on demand response (DR) since 1987. All of CLECA's members participate in investor-owned utility (IOU) DR programs. Thus, the proposed review of the role of DR in this rulemaking is of keen interest to them. CLECA's response is structured around the format of the Attachment to the Scoping Memo. As Phase 2 of the proceeding addresses Foundational Questions, we address these in the order set forth in the Attachment.

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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; some CLECA members are bundled service customers and some are Direct Access customers.

II. RESPONSE

1. BIRFUCATION

a. *In the Order Instituting Rulemaking (OIR), the Commission proposes to bifurcate the current demand response programs into demand-side and supply-side resources. (See Figure 1 below for the proposed realignment.) The OIR defines the demand-side programs as customer-focused programs and rates, and supply side resources as reliable and flexible demand response that meets local and system resource planning and operational requirements. Please comment on the terms, demand-side and supply-side resources, and the definitions provided. If you disagree with the terms and/or definitions, please provide your recommended changes and explain why your recommendation is more appropriate.*

The Scoping Memo states that the "foremost issue" is whether to bifurcate DR into "demand-side" and "supply-side" resources. The bifurcation concept raises concerns ranging from the terminology proposed for making the distinction, to its impact on how DR is valued, to whether this is a useful construct when applied to the services DR can provide. We address these points in turn.

1) Clearer Terminology Is Needed

First of all, the terminology used to characterize these two types of DR is not clear. We understand that rate design-driven DR is considered "demand-side". However, the term "customer-focused" as attributed to "demand-side" DR is not defined. Since customers provide *all* DR, any DR program or product must be viable for the customers participating; the application of this term "customer-focused" to only "demand-side" appears to disregard or discount the customer role on the proposed "supply-side." Furthermore, the word "reliable" is attributed to "supply-side" DR, but "demand-side" DR should not automatically be presumed unreliable. In addition, the term "flexible" is not defined. If the reference is to the CAISO's Flexible Resource Adequacy Criteria and Must Offer Obligation (FRACMOO) requirements, these have not been finalized for DR. In short, the Scoping Memo proposes a bifurcation based on unclear concepts.

2) DR Has Value and Should Affect Need Determination

Whether or not DR is "bifurcated", it is very important that DR be reflected in resource planning and resource adequacy, whether as a load modifier or a resource. DR should either count for RA or be used to adjust downward the load that determines the RA or future resource requirement so that its value is reflected in both planning and in daily grid operations. There has been an ongoing debate as to whether DR-related load reductions that are not part of the CAISO's markets are "visible" to the CAISO and, due to that visibility, should be used to reduce any Residual Unit Commitment (RUC). DR should not have to be bid into the CAISO markets to be "visible" to the operators; DR can be appropriately used to adjust the load forecasts given to the CAISO by the LSEs and those used by the CAISO to determine RUC. If this does not occur, double procurement takes place, devaluing the benefits of DR and wasting ratepayer money. Either as a load modifier or as a resource, DR should have an impact on the identification of any additional need for resources to serve load.

3) Don't Elevate Form over Function

Of critical importance, the proposed bifurcation between demand-side and supply-side should actually be secondary to the *most important question,* which is *"what are the services the DR is intended to provide"*? A set of services that covers the range of possible uses for DR, along with some of their requirements, is proposed below. This may prove a more productive starting point than bifurcation, since it includes not just the definition of the service, but also the operational requirements associated with that service.

The stated rationale behind bifurcation is "to prioritize demand response as a utility-procured resource."[2] The reason for our concern with bifurcation is that it can devalue both supply- and demand-side DR; supply-side, if the standard against which the CAISO judges supply-side DR is "flexible" fossil generation, and demand-side if it is not given appropriate value in achieving supply-demand balance and resource adequacy.

Let us be clear: CLECA is NOT saying that no DR should be integrated or bid into the CAISO markets. Rather, a decision on integration into those markets should first be based on clear considerations of CAISO bidding and dispatch needs and requirements; then both the operational costs and benefits (and adequate compensation) associated with participation and the costs and benefits to the customers providing the DR must be considered; finally, the issue of who controls any load adjustments and how the point of control affects customer participation will also need to be evaluated. (These considerations are discussed in more detail below in section 5).

Categorizing DR by the types of service it could provide and their requirements would enable prioritization of DR as a resource or load modifier and cost-beneficial integration of some types into the CAISO markets.

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2 Joint Assigned Commissioner and Administrative Law Judge Ruling and Scoping Memo, at 9.

4) Categories of Services from DR

The following types of service have been mentioned for DR:

a) Traditional peak-shaving

This service usually involves day-ahead notice or day-of notice that is 30 minutes or longer. It involves only load reductions. It enhances system reliability, although it can provide local benefits, e.g. if it reduces loading on an over-loaded substation. It is not used frequently, but provides significant benefits when needed. There will continue to be system peaks, so traditional peak shaving will have ongoing merit.[3] Traditional reliability DR programs like the Base Interruptible Program (BIP) clearly provide this service.

b) Local Reliability or Contingency Service

This service requires response within a fixed time frame and involves only load reduction. The CAISO expects that DR used to address a local reliability or transmission contingency would have to respond within 30 minutes. In response to a question from CLECA, the CAISO stated this requirement is based on its application of NERC Standard TOP-004 to an N-1-1 contingency where the CAISO has to be ready within 30 minutes after one event to deal with another event. If this is the appropriate standard, there is no reason why DR cannot fully respond within 30 minutes. The CAISO has also expressed concern that DR might fail to meet its obligation to respond to such a contingency.[4] However,

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[3] In addition to peak-shaving, there will also be interest in shifting load from peak to troughs during certain months to mitigate both peaks and minimum load problems. While there is a current methodology to estimate the costs avoided by peak-shaving, there is no current methodology to value increased load.

[4] Paper-Non-Conventional Alternatives-2013-2014Transmission Planning Process, pdf, at 14-15.

while the CAISO might prefer automation of this service or even CAISO direct load control (DLC) so that response can be assured, we do not see this as necessary. Where the response can be provided within the appropriate notice and response period, and assurance of performance can be accomplished through steep penalties for non-compliance, neither automation nor DLC is required. BIP has long assured performance through severe penalties for non-compliance, and that compliance record should assuage any CAISO concerns. Furthermore, it has not been demonstrated that this service needs to be bid into CAISO markets. It simply needs to be triggered at the appropriate time and have the required response time and appropriate penalties for non-performance.

This service provides local benefits, assuming that the contingency is localized, as would generally be the case. It is not likely to be used frequently, since contingencies should be rare. It should be seriously considered in lieu of additional fossil-fired generating capacity that will be very rarely used.[5] Insufficient attention has been paid to this type of DR and its specific operational requirements. The CAISO has had one stakeholder call on this topic on September 18, 2013, and its September 4 issue paper was highly conceptual and appeared to confuse contingency service with the need for ramping capability. Far more detail is required to fully define this service and its operational requirements. Once that detail is available, DR should be able to provide it.

[5] Under certain circumstances, the CAISO commits fossil-fired generation out of merit order at minimum load so that it can be ramped quickly in case of the loss of a network element; this results in both additional costs and GHG emissions. DR could be used instead.

c) Integration of intermittent renewable resources/load following

This service is the newest in concept and would involve a product that can be ramped and can follow load. It requires DR that can increase or decrease load and would likely be used much more frequently than peak-shaving or local reliability/contingency DR. It is most likely to provide system rather than local benefits. It would also most likely have to be bid into the CAISO markets so that it can be dispatched as needed. However, the service it provides must also be workable for the end-use load providing the DR. Thus, the customer must either control the response of its load or there must be enough diversity among the loads responding that a customer will not be forced to have its load adjusted outside of the bounds within which the customer is comfortable. If there is a must-offer obligation (MOO), any MOO must be manageable for the customers and/or the aggregators. Furthermore, longer ramping requirements than five minutes would be more workable for DR, e.g. 15-minute or hourly requirements. Since even combined cycle plants can have problems with five-minute dispatch, this should not be surprising. The only likely end uses capable of providing this service year-round would be electric HVAC, electric water heating, lighting, water pumping and refrigeration that can withstand minor adjustments. All-electric HVAC (e.g. involving electric heating) and electric water heating are not common in California.

d) Ancillary Services

These services are well-defined and can be self-provided or procured in the CAISO markets. DR providing ancillary services (A/S) would have to be integrated into those CAISO markets. DR has provided all A/S, including non-spinning reserve, spinning reserve, and regulation in other ISOs/RTOs. Due to WECC restrictions, however, DR has only been able to provide non-spinning reserve in the CAISO (although the requirements have recently changed). The market prices, however, have been too low to support DR provision of non-spinning reserve. Furthermore, the cost of required telemetry is and has been prohibitive. For more DR to participate in these A/S markets, lower-cost telemetry or an alternative must be developed. Since these are five-minute markets, automated response would most likely be required.

e) Frequency Response

This service would have to be automated through the use of under-frequency relays (UFRs). Customers on PG&E's BIP program have a UFR option. Clearly, UFRs involve a customer giving up control of part of its load, which will limit participation. If the technology is cheap, it could be used for some of the same end uses that can provide contingency reserves.

Figure 1 in Attachment One to the Scoping Memo contains a diagram that implies that all supply-side DR *will* be bid into the CAISO markets and furthermore that supply-side DR will increase over time. If "supply-side" indeed means bidding into the CAISO energy markets, the above discussion shows that this is not necessary for many of the services DR is expected to provide. Instead, the nature of the service should be the basis for determining whether it must be bid into the CAISO markets. Among the above list of services, it appears that only ramping/load following and ancillary services require that DR be bid into the CAISO markets and dispatched by the CAISO.

5) Four Considerations Should Inform CAISO Integration

On what basis should the decision be made that a type of DR has to be bid into the CAISO markets? There are at least four considerations. The first is whether the resource fits into the CAISO economic dispatch. Many of the services listed above do not require this. Since there are costs associated with bidding into and being economically dispatched in the CAISO markets, it is important to know whether this is truly required to provide the service. The second is the cost participating customers or their aggregators would incur should they bid into the CAISO markets and be economically dispatched. Current CAISO requirements, such as its settlement process and its telemetry requirements, are expensive and burdensome, particularly for smaller customers who might be capable of providing DR. Unless these requirements are simplified, the costs of bidding DR into the CAISO markets will deter participation. Further, while aggregation may serve to address some of these concerns for some customers, aggregation may not be a workable or acceptable solution for all customers.

The third is whether there is enough remuneration in the CAISO's markets to make customer participation a financially attractive proposition. If not, will there be a source of supplemental revenue to make participation worthwhile? The fourth is who would control changes in customer load. In most cases, customers will not allow their load to be controlled by a third party, i.e. direct load control or DLC, particularly non-residential customers. Some customers may allow their energy management systems to communicate with and respond through an automated process like OpenADR. These may be the best candidates for DR bid into the CAISO markets. Many industrial customers, however, have safety or production considerations associated with changing load levels that require careful management. Even among residential and small commercial customers, there is evidence that many prefer to have control over their response to a DR or dynamic pricing signal, e.g. the amount of temperature adjustment for their programmable communicating thermostats (PCTs). In short, from the customers' perspectives, DR is not a one-size-fits-all application. If participation in CAISO markets requires third-party dispatch, it will reduce participation.

b. *Are there any potential problems or concerns with the proposed bifurcation or realignment of demand response programs into demand-side and supply-side resources? For example, are there any legal issues or other concerns such as missed opportunities for integration?*

Figure 1 in Attachment One to the Scoping Memo states that supply-side DR will increasingly be acquired through a competitive capacity procurement mechanism. The use of a competitive capacity procurement mechanism may have some appeal because it implies that lower-cost services will be procured first, helping to control costs; this could be similar to the procurement of smaller renewable resources through the Renewable Auction Mechanism (RAM).[6] RAM has a "price-only" selection framework; each IOU conducts its own RAM, but the utility auctions are held simultaneously. Notably, the RAM required a large

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[6] *See* D. 10-12-048; *see also* D. 12-05-035.

amount of work to develop standardized protocols, IOU substation/circuit maps and standard form contracts. Furthermore, the RAM only procures three "types" of small renewable resources: baseload, peaking as-available and non-peaking as-available; DR may be asked to provide more varied services, which could result in increased complexity.

There may also be a wish to avoid the on-going debate about DR cost-effectiveness through competitive procurement. Certainly, the Scoping Memo mentions cost-effectiveness as a subject for this phase of the DR rulemaking, although it asks no questions about it. There are indeed still holdover issues related to cost-effectiveness from the last 3-year DR program decision.[7] In addition, the current cost-effectiveness methodology is strongly focused on peak-shaving DR. It has no way to evaluate the benefits of ramping or increasing load to avoid minimum load situations. It does not consider DR to avoid or mitigate transmission emergencies. There would be considerable additional work required to assess the value of these other attributes. If past experience is any indicator, consensus would not be easy to achieve.

Perhaps most importantly, this concept of an auction raises a litany of issues that have previously arisen regarding the FERC-jurisdictional nature of capacity markets. Stakeholders have claimed that a "capacity" market is required for DR. Certainly its value has historically been based on avoided capacity costs. Furthermore, the compensation for DR available through CAISO energy and A/S markets would be inadequate to motivate customer load changes. However, if some form of capacity payment is required, why should

[7] *See, e.g.*, D. 12-04-045, at 45-47.

that not continue to be provided through utility program incentives? These utility programs are clearly state-jurisdictional.

If the capacity payments are provided through a CAISO capacity market, such capacity markets are clearly FERC-jurisdictional if they are mandatory. FERC has jurisdiction over wholesale market prices.[8] In a number of recent cases, FERC and the courts have set rules even for voluntary capacity markets that erode state jurisdiction.[9] Furthermore, there are cases where states have attempted to exempt preferred resources from such markets and have been denied the ability to do so.[10]

If there is a desire to procure DR through some sort of competitive mechanism and to avoid providing an opening for a FERC-jurisdictional capacity market that will undermine state jurisdiction, it should not be run by the CAISO. The CAISO is a FERC-jurisdictional utility. Even a voluntary market could eventually become FERC-jurisdictional as the above-cited orders show. It is not clear that a "DR" or voluntary preferred resources auction run by the CAISO could avoid becoming FERC-jurisdictional, especially as the CAISO seeks to expand its footprint outside California. The RAM has avoided this situation; it is

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8 Federal Power Act (FPA), 16 U.S.C. § 791(a) et. seq.

9 *See, eg, PJM Interconnection, L.L.C. PJM Power Providers Group*, 137 FERC ¶ 61145 at P 89 (denying rehearing of order removing exemption for preferred resources from a minimum offer price rule despite the inclusion of the exemption in an earlier settlement with the state agency); *see also PPL Energyplus, LLC v. Nazarian*, No.12-1286 (D. Md. Sept. 30 2013) (Garbis, J.), mimeo at 86. ("Where a state action falls within a field Congress intended the federal government alone to occupy, the good intentions and importance of the state's objective are immaterial to the field preemption analysis.").

10 *See, eg*, NESCOE v. ISO NE, 142 FERC ¶ 61,108, Order Denying Complaint, rehearing granted Apr. 15, 2013 (concluding that FERC's interests in efficient wholesale markets and market prices outweigh a state's legitimate policy interest in promoting renewable resources and mandating application of the Minimum Offer Price Rule to renewable resources, even though it would undermine renewable resource development.).

not run by the CAISO but by the individual IOUs, and they retain discretion over which RAM bids to accept or reject. As the Commission stated:

> Under RAM we do not set the price, but rely on a market-mechanism that is compatible with FERC's rate-setting in wholesale markets. RAM avoids or eliminates the jurisdictional issue, and we adopt it, in part, for precisely this reason. The *reasonableness of this approach, however, relies on a critical assumption: the market is and remains sufficiently competitive to produce just and reasonable rates, result in efficient and optimal outcomes, and protect both buyers, sellers, and ratepayers.*[11]

An approach similar to RAM may work for some types of DR services; it warrants serious consideration as a more-viable market mechanism for DR procurement that preserves CPUC jurisdiction, as opposed to a CAISO-run auction.

> c. *The OIR describes an ongoing tension between the supply-side and demand-side requirements for demand response. The OIR states that demand response as resource adequacy resources are held to the same requirements as generation resources for system reliability and economic efficiency. Simultaneously, the needs and technical capabilities of customers and providers should also be considered in program design. How could the proposed bifurcation or realignment of supply-side and demand-side resources be designed to serve both sets of requirements*?

The Scoping Memo makes reference to expanded participation in the CAISO energy markets. This implies that any compensation in excess of CAISO energy prices that might be necessary to attract participation will come from elsewhere. The proposed services detailed above demonstrate that it is not necessary to require all DR to be bid into the CAISO energy markets; moreover, as shown above, such a requirement could actually reduce participation. Equally importantly, the CAISO energy and A/S markets are five-minute markets that are

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[11] *See* D. 10-12-048, at 20 (emphasis added); *see also id* at 21 ("The federal law issue is rendered moot in this decision because we preserve the IOUs' discretion to reject bids in instances of market manipulation or non-competitive pricing compared to other renewable procurement opportunities.").

not well-suited for DR, except for specific applications where ramping is required and where specific end-uses lend themselves to those applications. Will the CAISO consider 15-minute markets or 1-hour markets for DR? If not, most DR will not be able to bid into five-minute markets.

The CAISO market and its rules have largely been developed for generators, in particular gas-fired generators. As with five-minute markets, DR does not necessarily or generally perform like a gas-fired generator and even combined cycle plants are challenged to meet the requirements of these markets, not to mention intermittent renewable resources. There is indeed a tension between DR "being held to the same requirements as generation resources for system reliability and economic efficiency" and "considering the needs and technical capabilities of customers and providers". DR is not a generator. There are limited end uses with flexibility comparable to a gas-fired generator. Customers cannot meet the availability requirements being contemplated in FRACMOO, for example, without elaborate aggregation. Other ISO/RTOs do not have the same requirements for DR as for generation for telemetry or settlement. The presumption that the requirements must be the same would undermine the role that DR might be able to play and risks de-prioritizing DR, contrary to California energy policy.

In addition, there will have to be a determination of what need or needs would be met through DR or through competitive procurement of DR. Will there be a different need for each type of service DR is expected to provide? Who will determine the need? The CAISO determines need for system and local RA and is working on a process for determining the need for flexible capacity, although the latter has not been finalized and is in a stakeholder process. There is no defined "need" for peak-shaving.

If DR is bid into CAISO markets, can it be "optimized" by the CAISO for an array of services, given its use limitations? Unlike generation, can its costs be assumed to be monotonically increasing? These are unanswered questions. It makes more sense to first evaluate next summer's experience of bidding DR into CAISO markets and the results from the proposed pilots while exploring the suitability of DR for five-minute markets. Then an informed decision can be made on whether ever-increasing amounts of DR should be bid into these markets.

2. COST ALLOCATION

a. Current policy requires the utilities to identify, in their demand response applications, the rates used for cost recovery of each program and the justification for that rate. What, if any, additional information should the Commission require to ensure equitable cost allocation and why?

The Scoping Memo raises the issue of cost allocation with respect to DR. This issue clearly relates to the allocation of costs associated with utility DR programs. In the past, these costs have been allocated to all LSEs whose customers take CPUC-jurisdictional delivery service on the grounds that the customers of all these LSEs can participate in IOU DR programs and that all benefit from the value of DR.[12] In return, the LSEs receive a load-ratio share of

[12] This is similar to the Commission's determination that all customers benefit from new system generation, although only IOUs can sign long-term contracts to allow new generation to be built.

the RA value of the DR. Certain non-IOU LSEs have argued that they would like to provide their own DR programs. It may also be that some would prefer to substitute another form of RA, which in the current market would be cheaper than utility DR programs.

In order to address the cost allocation issue, the Commission must consider whether all LSEs serving customers that are under its jurisdiction (at least for delivery services) would have any DR-related obligation. Is DR just a form of load modifier or resource that counts for or against an RA requirement, or is it something more? If the Commission is considering reinstating a DR target (e.g. as a percentage of load, and something we are NOT recommending), why should it apply to IOUs and not other LSEs?

Currently, the costs of utility DR programs are not necessarily allocated the same way for each IOU. In large part, this is because these allocations are part of settlements of the Phase 2 of each IOU's general rate case that have been adopted by the Commission. CLECA believes that the allocation of such costs should continue to be addressed in Phase 2 of each General Rate Case; these dockets are devoted to cost allocation matters involving many different types of costs, some of which do not fall neatly into the categories of generation or distribution.

However, if the Commission decides it wants to address the matter in this rulemaking, it must answer certain threshold questions:

- What is the nature of each LSE's DR obligation? Is it simply an RA obligation or is there some intention to pursue an explicit DR obligation?
- Who can participate in which LSE's DR programs?

- What is the nature of the service provided by the DR programs? Are they all fungible or not? Is their cost structure the same or not?

Without answers to these questions, no informed decision can be made about a cost allocation policy explicitly related to DR.

b. *If the Commission bifurcates the demand response programs into demand-side and supply-side, does it need to revise its requirements for cost allocation in order to ensure equitable cost allocation? How and why?*

Regarding demand-side DR, to the extent that this represents rate design, the Commission has no authority over ESP or CCA generation pricing. If the Commission were to decide to make significant changes to delivery rates in order to impose some pricing requirements, this would be highly controversial. Such changes definitely should be addressed in a Phase 2 of a general rate case, not in this rulemaking. Other than rate design, we believe that the points made above apply. In addition, the costs of implementing rate design changes are functionally customer service-related, and thus recoverable through delivery charges.

c. *In resource adequacy procurement, costs are allocated across the LSE's (sic). If the Commission bifurcates demand response programs into demand side and supply side, should costs for supply-side procurement be allocated in the same fashion as resource adequacy procurement? If not, recommend other frameworks?*

See response to b.

3. BACK-UP GENERATORS

a. *In D.11-10-003, Conclusion of Law No. 5 states, "fossil-fueled emergency back-up generation resources should not be allowed as* *part of a demand response program for resource adequacy purposes." The decision required the utilities to work with Commission staff to identify data regarding the use of back-up generators. The Utilities shall provide a description of data they have on customer back-up generator usage in demand response programs. We request other parties to share this information as well.*

There is no reason why anyone other than the customers themselves or their air quality regulators should know if they have back-up generators. These customers are all subject to appropriate air quality regulations. It is not the CPUC's jurisdictional responsibility to enforce air quality regulations.

b. If the Commission bifurcates demand response programs, how should the Commission develop rules that are consistent with the D.11-10-003 policy statement?

No response provided at this time; CLECA reserves the right to reply to other parties' responses.

c. What are the current laws and regulations regarding back-up generation, including those by the Air Resources Board, local air quality management districts and/or any other related regulatory body?

No response provided at this time; CLECA reserves the right to reply to other parties' responses.

III. CONCLUSION

CLECA appreciates the opportunity to respond to the foundational questions on bifurcation and cost allocation. As detailed above, categorizing DR by the various types of services being sought would distinguish the different types of DR and help inform the determination on integration into CAISO markets. While different from the proposed bifurcation, CLECA's recommended approach serves the same goal: prioritizing and enhancing DR. As the

Commission and parties progress toward this shared goal, existing DR should be enabled to continue to enhance reliability, save ratepayer dollars by avoiding unnecessary procurement, and help reduce carbon emissions.

Respectfully submitted

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December 13, 2013