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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas & Electric Company (U 39-E) for Approval of Demand Response Programs, Pilots and Budgets for Program Years 2018-2022.	Application 17-01-012 (Filed January 17, 2017)
And Related Matters.	Application 17-01-018 Application 17-01-019

JOINT OPENING COMMENTS OF CPOWER, ENEL X NORTH AMERICA, INC., OHMCONNECT, INC., LEAPFROG POWER, INC., AND CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL ON PROPOSED DECISION ADDRESSING AUCTION MECHANISM, BASELINES, AND AUTO DEMAND RESPONSE FOR BATTERY STORAGE

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CPower, Enel X North America, Inc. (formerly known as EnerNOC, Inc.), OhmConnect, Inc., Leapfrog Power, Inc. and California Efficiency + Demand Management Council, collectively known as the "Joint Parties", respectfully submit these Joint Opening Comments on the Proposed Decision of Administrative Law Judge (ALJ) Hymes "Addressing Auction Mechanism, Baselines, and Auto Demand Response for Battery Storage" (Proposed Decision or PD) mailed in this proceeding on May 31, 2019. These Joint Opening Comments are timely filed and served pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure and the instructions accompanying the Proposed Decision.

I.
THE PROPOSED DECISION MUST BE MODIFIED ON THE DRAM BUDGET.

A. The Proposed Decision should be revised to maintain the 2019 DRAM Budget for the four-year pilot extension at $27 million.

The Joint Parties greatly appreciate the four-year extension of the DRAM approved by the Proposed Decision.[1] This will provide greater market certainty than the current year-to-year approach and allow time to implement further modifications to the DRAM in order to improve performance. However, the Joint Parties respectfully note that the PD mischaracterized the budget for the 2019 DRAM at $14 million. The PD states:

[1] Proposed Decision, at Ordering Paragraph 2.

"[W]e *maintain the current funding levels* and authorize annual budgets of $14 million for solicitations in 2020 through 2022 ($6 million each for PG&E and SCE and $2 million for SDG&E) and a pro-rated total budget of $8.2 million for a shortened (i.e., 7 months) demand response season for the 2019 solicitation ($3.5 million each for PG&E and SCE and $1.2 million for SDG&E). This authorization of $50.2 million allows for deliveries in 2020 through 2023."[2] (emphasis added)

The DRAM budget for 2019 deliveries was $27 million, not $14 million. In its Decision (D.) 17-10-017), the Commission authorized a total budget of $13.5 million ($6 million each to PG&E and SCE, and $1.5 million to SDG&E) for a DRAM auction in 2018 with deliveries in 2019.[3] However, this funding was *incremental to* funding authorized in D.16-06-029 and Resolution E-4817 for a DRAM solicitation in 2017 for deliveries in 2018 and 2019.[4] Specifically, D.16-06-029 authorized a total budget of $27 million ($12 million each to PG&E and SCE, and $3 million to SDG&E) while Resolution E-4817 directed the investor-owned utilities (IOUs) to apply this budget to incentive payments in 2018 and 2019.[5] The $27 million budget for 2019 is reflected in the re-creation of Table 6, shown below, of the Energy Division's Evaluation of Demand Response Auction Mechanism Final Report (Evaluation Report) which shows a total 2019 budget of $27 million.[6]

Table 1. DRAM Budgets 2016-2019

DRAM Budgets ($ millions)						
IOU	**2016**	**2017**	**2018**	**2019**	**Total**	**Annual Avg.**
SCE	4.0	6.0	6.0	12.0	28.0	7.0
PG&E	4.0	6.0	6.0	12.0	28.0	7.0
SDG&E	1.0	1.5	1.5	3.0	7.0	1.75
Total	9.0	13.5	13.5	27.0	63.0	15.75

Therefore, the PD would cut in half the current DRAM funding levels, beginning with deliveries in 2020, and hold that level constant over a four-year period. If the annual auction

[2] Proposed Decision, at p. 31.
[3] D.17-10-017, at pps. 47-48.
[4] D.16-06-029, at Order Paragraph 21; Final Resolution E-4817, at Ordering Paragraph 8.
[5] Resolution E-4817, Ordering Paragraph 8.
[6] Energy Division Evaluation of Demand Response Auction Mechanism Final Report, at p. 20.

budget is reduced to only $14 million, there is certain to be a net reduction in DRAM capacity procurement below the current 368 MW for the next four years.[7] This will force many demand response (DR) providers to reduce the number of customers that are currently participating in DRAM, reversing the gains cited in the Proposed Decision as one of the successes of the pilot: attracting new customers. As the PD notes, "[d]uring the 2016 and 2017 delivery years, 74 to 95 percent of customers enrolled in demand response through the Auction Mechanism had not previously participated in a Utility demand response program."[8] Given that growth in new DR customer participation is one of the six key criteria on which the permanency of the DRAM hinges, it would be counter-productive to approve a budget for the next four years that could reverse that growth, especially given the IOUs' recent status report on progress toward the interim 5% goal approved in D.14-12-024 indicates that they are far from reaching it.[9]

The proposed budget may also have a suppressing effect on the interest of new entrants to participate in the DRAM, negatively affecting another of the six key DRAM evaluation criteria. New entrants will see the diminished market opportunity in California and wonder why the state with the most progressive clean energy goals has a budget limitation on wholesale DR participation (outside of the IOUs) whereas other markets do not.[10]

To preserve the growth in DR participation that has been driven by the DRAM, the PD should be revised to maintain the current funding level of $27 million for the four-year extension period. Should the 2019 DRAM improvements lead to significantly improved DRAM performance, the Joint Parties recommend that the budget be revisited at a future date.

B. The 2019 DRAM solicitation should not be based on a straight linear proration.

The PD proposes a prorated 2019 solicitation budget for deliveries beginning in June 2020. Based on a $14 million annual budget and seven months of deliveries in 2020, the prorated budget is calculated to be (7/12) * $14 million = $8.2 million. This approach is logical on the surface, but it does not reflect the higher capacity value of the summer months relative to the first four winter months of the year. As a consequence, less DRAM capacity will be

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[7] Energy Division Evaluation of Demand Response Auction Mechanism Final Report, at p. 20.
[8] Proposed Decision, at p. 13.
[9] Joint IOU Status Report on Progress Toward Interim Goal Approved in Decision 14-12-024, June 17, 2019.
[10] These include PJM Interconnection (PJM), New York Independent System Operator (NYISO), Midcontinent Independent System Operator (MISO) and Independent System Operator New England (ISO-NE).

available when it is needed the most. To illustrate this point, the total capacity price in PG&E's Capacity Bidding Program (CBP), which is available May-October is $62.07/kW-year. If the CBP was restricted to June-October, the remaining capacity price would be $58.89, 95% of the total capacity value of the CBP. The Commission should similarly weight the prorated DRAM budget for 2020 deliveries toward the higher value summer months which would result in a budget of 0.95 * $27 million = $25.65 million based on a $27 million annual budget. Alternatively, the Commission could prorate based on the actual value of the capacity purchased for 2019 delivery for the months of June or May through December. This would ensure that a similar amount is spent in 2020 for the same months as in 2019.

C. The $2.8M budget authorized for "evaluation" of the next phase of DRAM should be incremental to the funding for capacity payments.

The Proposed Decision directs the appointment of a consultant to perform quarterly and annual monitoring and evaluation work with an approved budget of $2.8 million.[11] The Joint Parties presume that this amount would be spread across the four-year extension period in which case this amount would translate into a $700,000 budget per year. This budget should be incremental to the approved DRAM budget. Even if the Commission approves a $27 million annual budget, this new expense would reduce the procurement budget below current levels.

III.
THE PROPOSED DECISION MUST BE MODIFIED ON THE DRAM SOLICITATION.

A. The 2019 auction schedule can be compressed to allow for deliveries starting May 2020.

In the proposed schedule for the 2019 solicitation, approximately three months elapse between the October 11, 2019 Request for Offer (RFO) launch and the January 10, 2020 submission of Tier 1 advice letters with executed contracts.[12] While this period of time is consistent with the IOUs' most recent auctions, it is not entirely evident that three months are indeed necessary. In fact, in its response to the February 28 ALJ Ruling, SCE included a proposed schedule that already shortened this period to two months.[13] In the proposed alternative schedule below, the Joint Parties request that the PD be modified to shorten the period between the RFO launch and the submission of advice letters to two and a half months. Winning bidders

[11] Proposed Decision, at Ordering Paragraph 15.
[12] Ibid, at Ordering Paragraph 4.
[13] Southern California Edison Company Response to Administrative Law Judge's Ruling Directing Responses to Questions Resulting from the February 11-12, 2019 Demand Response Auction Mechanism Workshop and Comments on Proposals to Improve the Mechanism, at p. 6.

would then have a full two months to complete all necessary registrations and aggregate their resources, submitting the first monthly supply plan on March 1, 2020. The Joint Parties see no need to delay the delivery period to June 1, especially considering that the Summer period begins in May. To ensure that DRAM resources will be available for the entire Summer period, a time when DR resources provide the most value to the grid, the Joint Parties recommend that the initiation of deliveries be moved up to May 1, 2020 with first supply plans due on March 1. With this addition, the prorated budget for the 2020 delivery year would need to be adjusted accordingly.

Table 2. Proposed Schedule for 2019 Solicitation with First Deliveries in 2020

Activity	Date
Joint Utilities Submit Tier Two Advice Letters with Contract Improvements and Request for Offer Guidelines	August 12, 2019
Commission Approves Advice Letters	September 11, 2019
Utilities Launch Request for Offers for Deliveries Beginning 2020	October 4, 2019
Utilities Submit Tier One ALS with Executed Contracts	December 16, 2019
First Supply Plans Submitted	March 1, 2020
Deliveries Begin	May 1, 2020

B. The DRAM pilot extension should utilize one-year auctions.

As stated above, the Joint Parties appreciate and support the PD's approval of a four-year extension of the DRAM pilot through 2022. However, the PD is silent on whether the Commission envisions four, one-year solicitations or a smaller number of multi-year solicitations. The Joint Parties assume the intent of the Commission is for four, one-year solicitations and recommend that the PD specify this.

C. The PD should be clarified to allow both System and Flexible RA in the 2019 Auction.

Because the 2019 solicitation will not occur in time for the winning bids to be incorporated into the IOUs' year-ahead resource adequacy (RA) filings, it is clear that Local RA products cannot be procured. However, because only 90% of System and Flexible RA requirements must be submitted in the year-ahead demonstration, the Joint Parties request that the Proposed Decision be revised to specify that System and Flexible RA may be procured in the

2019 solicitation and that all three types of RA (System, Local, Flexible) may be procured in the remaining three solicitations.

D. PD revisions are required to allow Tier 1 advice letters for all DRAM pilot contracts.

The Joint Parties support allowing the IOUs to submit a Tier 1 advice letter for the executed contracts.[14] Given the pro forma nature of the DRAM contract, this is a reasonable approach that will save time and, with the participation of the Independent Evaluator and Energy Division staff in the Procurement Review Groups, should provide a reasonable amount of oversight. However, it is not clear whether the Commission intends for this practice to apply solely to the 2019 solicitation or to all four solicitations. The Joint Parties recommend this practice apply throughout the four-year extension period to reduce the solicitation timelines and allow the procured capacity to be included in the IOUs' year-ahead RA filings. This practice can be re-evaluated should the DRAM be extended further.

IV.
THE PROPOSED DECISION SHOULD BE MODIFIED TO ADEQUATELY ADDRESS QUALIFYING CAPACITY.

A. It is impractical to require information with bids and year-ahead supply plans.

The Joint Parties are very supportive of improving the accuracy of Qualifying Capacity and Demonstrated Capacity estimates of DRAM resources. Indeed, Table 2 in the Proposed Decision appears to demonstrate that DRAM Sellers' performances have improved significantly.[15] Despite this, the Proposed Decision requires the provision of historical performance data, at the resource or contract level, as appropriate, when submitting a bid in a DRAM solicitation, and when filing year-ahead and month-ahead supply plans.[16] The Joint Parties are supportive of providing information with their month-ahead supply plans, and at the resource level, because their customer composition will be known at that point in time. However, providing historical performance data at the time of solicitation and year-ahead supply plans is highly problematic for several reasons.

First, historical performance data, either at the contract or resource level, has little relevance to future performance because from one year to the next, the customer composition could change significantly due to customer departures and enrollments with different DRAM

[14] Proposed Decision, at pps. 32-33.
[15] Proposed Decision, at p. 24.
[16] Ibid, at Ordering Paragraph 7, Appendix A.

Sellers. Therefore, it is unlikely that a resource will be the same year-over-year. Furthermore, the proliferation of new community choice aggregators (CCA) could add another element of uncertainty to the ability of DRAM Sellers to predict the composition of their customer portfolios so far ahead of the delivery month.

Second, the PD provides no detail on what constitutes an acceptable source of generic, publicly available per-customer load reduction capability nor a dispute resolution process should the Commission, Independent Evaluator, or IOU reject the source put forth by the DRAM Sellers. This is particularly relevant because customers rarely decide at the time of the solicitation or year-ahead supply plan to participate in a DR program, so DRAM Sellers would often have no other choice but to cite a generic source and estimate the number of customers they would need to provide the capacity specified in their contract (should they be awarded one). The Joint Parties are not certain what value this information would provide to the Commission. Moreover, since these are estimates, a DRAM Seller would not want to be evaluated negatively if it added different types and quantities of customers than it assumed in its bid.

Third, if the purpose of providing data is to ensure that the contracted amount of capacity is delivered, the Demonstrated Capacity and contract default penalties provide sufficient motivation to perform at the contract quantity. The Joint Parties are concerned by what appears to be a "pancaking" of multiple requirements and penalty structures all to achieve the same goal.

Lastly, applying this requirement to all DRAM Sellers, particularly those that have a track record of performing well relative to their bids and/or supply plans in the past, would be counterproductive.

Should the Commission ultimately adopt these requirements the final decision should clarify that, at the time of bidding, and in the year-ahead supply plan, both customer load and references to historic performance should be made available *at the aggregate (anticipated) contract level*. From an operational perspective, these two milestones occur far too early for a DRP to be able to accurately forecast which customers will comprise a given resource. Any attempt to do so would be so imprecise as to render the output useless.

B. The PD must be revised to mandate that a third party review DRAM Sellers' resource capacity estimation.

The Joint Parties have grave concerns about the IOUs being the party to assess the DRAM Sellers' resource capacity estimation.[17] This gives the utilities significant insight into the DRAM Seller's process for determining its customer resources and capacity that is considered market sensitive and confidential. If there is a failure to appropriately protect that data, it would reveal significant sensitive information about a DR provider's practice of estimating load by customer or customer type. The Joint Parties prefer an independent objective party, such as the consultant or Independent Evaluator, with the appropriate confidentiality protections in place, to determine its reasonableness. In addition to the benefit of objectivity, a third party would apply a consistent and uniform standard across all IOU service areas. Otherwise, it is easy to foresee each IOU applying its own unique standard to the interpretation of the data, greatly complicating compliance with this requirement for DRAM Sellers that participate in multiple IOU solicitations. Should the Commission determine that the IOUs should be the ones to assess these data, customers' data should be aggregated to the contract level to preserve the confidentiality of the DRAM Sellers' customers.

V.
THE REQUIRED NUMBER OF DEMONSTRATED CAPACITY DISPATCHES IS EXCESSIVE AND NOT CONSISTENT WITH OTHER MARKETS.

The Proposed Decision proposes a requirement that the Demonstrated Capacity of each DRAM resource be based on either test events or dispatches in six out of the twelve months of the year.[18] A minimum dispatch requirement outside of standard testing does not exist in any other market in the United States and it is not clear why one is needed in California. The current DRAM testing requirements already exceed DR testing requirements in other markets, where no more than a single test event is required each year or season (summer/winter). As shown in Table 3 below, all other major markets require only a single test event or dispatch each year.

[17] Proposed Decision, at Ordering Paragraph 8.
[18] Ibid, at p. 61.

Table 3. Demand Response Testing Requirements in Other Wholesale Markets

Market	Test Event/Dispatch Requirement
NYISO[19]	(1) one-hour test at the resource commitment level or dispatch every six months
MISO[20]	No test required if performance data from previous Planning Year available; otherwise, single test event
ISO-NE[21]	(1) one-hour test every season (six months)
PJM[22]	(1) one-hour test event (by committed capacity) each year if no dispatch
ERCOT[23]	One test event by ERS resource every 330 days.

In these other markets, DR tends to be dispatched very infrequently. As discussed further below, higher frequency dispatches are closely tied to whether the Commission views DRAM as a pure RA product or a mechanism to supplant power plants and reduce power sector emissions. For example, the Proposed Decision states that DRAM was not dispatched frequently during high demand events.[24] Since DRAM is an economic resource that is not triggered by other factors, it is unclear if there was a strong correlation between high demand events and high energy prices in the wholesale market. When DRAM resources should be dispatched (if not purely for economic reasons) is a policy question that should be undertaken as part of Step 2 or a future refinement process. The Commission should not preempt the outcome of that discussion by adopting a rigorous dispatch/testing requirement in this Proposed Decision. Frequent testing or uneconomic dispatch will occur in months when the resource is unlikely to be needed and may reduce the hours of availability for dispatch when it is needed. For customers for whom dispatches have low operational impact, DRAM Sellers are already able to bid them into the market at prices that effect more regular dispatch. Conversely, customers with a high

[19] New York Independent System Operator Frequently Asked Questions for Prospective Resources, p. 2, September 12, 2018.
[20] Midwest System Operator Resource Adequacy Business Practice Manual (BPM-011-r20), p. 60, November 1, 2018.
[21] Market Rule 1, Section III.1.5.1.3.1(a), (b), (c), and (d), April 1, 2019.
[22] PJM Manual 18: PJM Capacity Market, Revision 41, at p. 57 and p. 185, January 1, 2019.
[23] Electric Reliability Council of Texas, Emergency Response Service, Technical Requirements, Section 19. 1.A.: (iii), (iv), (v), (vi), April 8, 2019.
[24] Proposed Decision, at p. 14.

opportunity cost can opt for a lower level of dispatch (and lower energy payment revenue) but still be available in case of higher market prices. By mandating frequent testing or dispatch, the Commission will artificially limit the pool of DR customers by causing customers with a high opportunity cost of curtailment to opt not to participate.

In addition to these concerns, the Proposed Decision must be clarified to state that in contracts of shorter than a 12-month duration of active delivery any Demonstrated Capacity protocol should be prorated to the actual months of delivery.

If the intention behind adopting a minimum dispatch requirement is to ensure that DRAM resources are real and DRAM Sellers deliver on their contracts, the Joint Parties note that the Proposed Decision is adopting several other significant measures to ensure this occurs. The Demonstrated Capacity penalties, triggers for default, supporting data in supply plans, and linking the disposition of the DRAM to success in meeting the six key criteria, combine to provide an incentive for DRAM Sellers to deliver on their contracts. However, adding a frequent dispatch/testing requirement on top of that package of controls risks utilizing the resources in periods of low value to the grid. Furthermore, some of the Joint Parties have had difficulty in getting a market dispatch, even when bidding at the Net Benefits Test threshold price, which is the minimum price, determined by FERC, which DR resources are economically allowed to bid into ISO energy markets.

VI.
THE PROPOSED DECISION MUST BE CLARIFIED ON INVOICING AND RQMD.

The Proposed Decision adopts a requirement that the DRAM Seller submit an invoice to the IOU within 30 days of receiving 95% of Revenue Quality Meter Data (RQMD) from the IOU for a resource's dispatch event. If the DRAM Seller does not receive 95% of RQMD, it may submit a partial invoice.[25] The Joint Parties note that some details are missing in this approach while also ignoring the IOUs' responsibility to provide timely RQMD to the DRAM Sellers.

One key detail needing specification is the definition of 95% of RQMD. The Joint Parties recommend that 95% of RQMD be defined as 95% of the intervals of all events in a month for a given DRAM resource ID.

While timely receipt of revenue through invoicing of the IOU is important, so is the accuracy of the underlying data. The option provided by the Proposed Decision to submit a

[25] Ibid, at Ordering Paragraph 11.

partial invoice is a distant second-best to receiving timely and accurate RQMD from the IOU. Allowing for a partial invoice still negatively affects the DRAM Seller by potentially reducing the amount of revenue it can receive. Moreover, it does not provide the right incentives to the IOU to modify its processes in order to meet its obligations to provide timely and accurate data. Instead of submitting a partial invoice, the Joint Parties would prefer to submit an invoice using as much RQMD data as has been timely provided. For the balance of the missing data, the Joint Parties would prefer to submit an invoice to the IOUs using Commission-approved Validation, Editing and Estimation (VEE) methodologies within 30 days after settling with the CAISO. Within 30 days of receipt of complete and accurate RQMD data, the DRAM Seller can submit an adjusted invoice if the RQMD data show a greater load reduction than the VEE data. In most instances, the DRAM Seller will be forfeiting resettlement with the CAISO because of the costs associated with resettlement. If the VEE data show a greater load reduction than the RQMD, there should be no invoice adjustment. This provides some, although likely not a significant, incentive to the IOUs to meet their obligations under Electric Rule 24/32 (Rule 24/32).

The PD does not address situations when the IOU delivers some or all RQMD only after several months, thus causing a delayed capacity payment to the DRAM Seller. The IOUs should be held accountable for their obligations under Rule 24/32 but the PD introduces no additional rigor to improve IOU performance in this area. DRAM Sellers are often not large, established companies and cannot afford to have their payments delayed through no fault of their own. The Joint Parties look forward to discussing this issue further in the Step 2 process.

VII.
RDRRS SHOULD NOT BE EXCLUDED FROM THE DRAM.

The Joint Parties disagree with the premise on which the PD excludes Reliability Demand Response Resources (RDRRs) from the DRAM. The PD argues that the role of RDRR in the DRAM should be limited because it is not designed to be used on a regular basis to address grid reliability needs and cites the CAISO's assertion that the DRAM should be used to procure resources that can avoid or defer the need for existing or new greenhouse gas emitting resources.[26] As a practical matter, the Joint Parties note that the difference in the minimum number of dispatch hours of a typical Proxy Demand Resource (PDR) and RDRR is not so large as to have any appreciable impact on the amount of greenhouse gas emissions that are offset.

[26] Ibid, at p. 43.

For example, assuming the Proposed Decision's minimum dispatch requirements only apply to PDRs, a PDR must execute a one-hour market dispatch in six different months within a 12-month period for a total of six hours of dispatch. Assuming an RDRR continues to be subject to a single annual two-hour test, it would dispatch a minimum of two hours per year. By any definition, the PDR's four greater hours of dispatch time will have virtually no significant impact on aggregate greenhouse gas emissions.

No party has demonstrated that the frequency of dispatch of a DR resource is related to its ability to avoid or defer the need for existing or new greenhouse gas emitting resources. DRAM resources (both PDRs and RDRRs) provide RA which is used to meet the RA requirements of the IOUs and other LSEs regardless of how much they are dispatched. The RA provided by DRAM resources (PDRs and RDRRs) displaces RA that would otherwise be provided by greenhouse gas-emitting resources. The reason behind the Commission's decision to cap RDRRs was the infrequent dispatch of these resources, so it is unclear why additional limits must be placed on RDRRs. If the Commission wants to declare that RDRRs are not dispatched frequently enough for the purposes of participation in the DRAM, parties should first have the opportunity to respond to a formal proposal that includes a definition of "frequently enough".

DRAM is about integration of resources into the wholesale market for purposes of providing RA. RDRR is one of only two methods of meeting that directive. Elimination of DRAM participation in RDRR closes another door for DR participation. The Commission went to great lengths to establish a hierarchy for participation in RDRR and the Base Interruptible Program (BIP) under the reliability cap approved in D.18-12-029.

Excluding RDRRs from the DRAM would disadvantage DRAM Sellers vis a vis the IOUs because the IOUs would regain the reliability program headroom for their own DR programs that is lost by DRAM Sellers. This is contrary to the principle adopted in D.16-09-056 that "[d]emand response shall be market-driven leading to a competitive, technology-neutral, open-market in California with a preference for services provided by third-parties through performance-based contracts at competitively determined prices, and dispatched pursuant to wholesale or distribution market instructions, superseded only for emergency grid conditions."[27]

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[27] Decision 16-09-056, at Ordering Paragraph 8.

At minimum, if the Commission upholds the proposed RDRR exclusion, the Commission should allow the DRAM Sellers with RDRR DRAM contracts to retain their headroom and direct the relevant IOU(s) to accept the associated customers into their BIP.

VIII.
THE DEFINITION OF "NEW ENTRANT" SHOULD BE REVISED.

The Joint Parties are supportive of replacing the 20% residential set-aside with the 10 percent new entrant set-aside but are concerned the definition of a "new entrant" unfairly limits DR providers participating in IOU DR programs.[28] The PD defines a new entrant as "as a Provider who has not had any business arrangement with any of the Utilities during the three years prior to a new Auction Mechanism solicitation involving any form of demand response including but not limited to Utility demand response programs, the Auction Mechanism, or other resource adequacy contracts."[29] Participation in an IOU DR program does not require the DR provider to be capable of directly participating in the CAISO market which is a significant technical requirement of the DRAM. As the Evaluation Report indicates, CAISO market integration represents a significant barrier to entry in the DRAM so any DR provider that can transition from an IOU DR program participant to a DRAM participant is effectively a new entrant to the DRAM because of the significant incremental increase in complexity associated with market integration.[30] The Joint Parties recommend the following revised definition of new entrant: a Provider who has not had any business arrangement with any of the Utilities during the three years prior to a new Auction Mechanism solicitation involving any form of market-integrated demand response including but not limited to the Auction Mechanism or other RA contracts.

IX.
THE STEP 2 SCHEDULE IS AMBITIOUS GIVEN THE SCOPE OF ISSUES.

The Joint Parties generally support the two-step approach adopted in the PD so that the DRAM can be assessed beginning in 2020 with most key issues addressed. However, given the large number of issues in the proposed scope, the Commission should consider adding two more working group meetings. The July 22 and July 29 meetings fall on Mondays, so additional meetings could be scheduled for July 23 and July 30. Otherwise, assuming that each meeting

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[28] Proposed Decision, at p. 41.
[29] Ibid.
[30] Evaluation Report, at pps. 36-39.

consists of five hours of working time, parties will have ten hours to address the eight issues listed in Table 6 of the Proposed Decision. Adding two more workshop days would leave 20 hours to address the Step 2 issues which seems more productive.

In addition, the Commission should consider whether a successor to the August Bid Price is actually needed. At the very least, this could be assessed in the next DRAM evaluation report. The IOUs' approach to selecting winning bids prior to approval of the August Bid Price appeared to function reasonably well so it should not be considered a foregone conclusion that it needs to be replaced rather than eliminated.

The Joint Parties recommend that Dispute Resolution Process be added to the Step 2 scope. Specifically, more rigorous rules are needed regarding the issues available for dispute, payment withholding during a dispute, and timelines for resolution. This was an Energy Division recommendation in the Evaluation Report.[31]

X. MONTHLY REPORTING IS UNNECESSARY AND PROVIDES NO DRAM BENEFIT.

The PD adopts a monthly reporting requirement on the basis that it will increase visibility into performance and improve reliability of DRAM resources.[32] In so doing, it disregards without explanation the comments of the Joint DR Parties and the Council that such frequent reporting will provide no value and does not explain how monthly reporting will improve the reliability of DRAM resources.[33] It is not clear that Energy Division will be able to process all of this data in a timely manner to provide meaningful analysis of the DRAM. Without a process in place to act on this monthly data, it is unclear how monthly reporting will increase visibility into performance and improve the reliability of DRAM resources relative to less frequent reporting. Furthermore, monthly reporting will be an unnecessary burden on some DRAM Sellers when less frequent reporting would provide the same benefits. Instead, the Joint Parties propose that quarterly reporting to an Independent Evaluator would be more efficient, subject to confidentiality protection of the detailed data.

[31] Evaluation Report, at pps. 116-117.
[32] Ibid, at p. 70.
[33] Proposed Decision, at pps. 69-70.

XI.
MODIFICATIONS SHOULD BE MADE TO THE PD REGARDING DR BASELINES

The Joint Parties appreciate the Commission's willingness to consider this baseline but recommend a more accelerated time frame. The Joint Parties recommend that the Commission adopt a faster timeline such that a determination on the 5-in-10 baseline can be made in the context of the December 2019 decision. Specifically, the Commission should direct the IOUs to include estimated costs and a timeline for implementing the 5-in-10 CBP baseline in an advice letter on August 9, 2019, the same day the Step 2 working group report is due.

The Commission should direct the IOUs to include in their costs and timeline assessment of the 5-in-10 baseline a proposal for implementing the FERC approved control groups measurement option for the CBP. OhmConnect previously provided some high-level insights into how this could be done.[34] Control groups are an especially effective measurement tool for residential DR due to the general homogeneity of the resource relative to non-residential customers and, given that SCE and SDG&E will be introducing residential CBP pilots in their mid-cycle reviews, the inclusion of measurement via control groups would provide them and PG&E's existing residential CBP with a baseline option tailored for residential customers.

XII.
CONCLUSION

The Joint Parties appreciate the opportunity to comment on the Proposed Decision.

Respectfully submitted,

June 20, 2019

/s/ MEGAN M. MYERS
Megan M. Myers
On Behalf of
CPower, Enel X North America, Inc.,
OhmConnect, Inc., Leapfrog Power, Inc. and
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[34] Response of OhmConnect, Inc. to ALJ Ruling Directing Responses to Questions and Filing of Previous Demand Response Baseline Development and Implementation Costs, at pps. 5-6.

APPENDIX A

CPOWER, ENEL X NORTH AMERICA, INC., OHMCONNECT, INC., LEAPFROG POWER, INC. AND CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDERING PARAGRAPHS FOR THE PROPOSED DECISION OF ALJ HYMES

CPower, Enel X North America, Inc., OhmConnect, Inc., Leapfrog Power, Inc. and California Efficiency + Demand Management Council propose the following modifications to the Findings of Fact, Conclusions of Law, and Ordering Paragraphs in the Proposed Decision of ALJ Hymes mailed in A.17-01-012, et al., on May 31, 2019 (Proposed Decision).

Please note the following:

- A page citation to the Proposed Decision is provided in brackets for each Finding of Fact, Conclusion of Law, or Ordering Paragraphs for which a modification is proposed.
- Added language is indicated by **bold type**; removed language is indicated by **bold strike-through**.
- A new or added Finding of Fact, Conclusion of Law, or Ordering Paragraph is labeled as "**NEW**" in **bold,** underscored capital letters.

PROPOSED FINDINGS OF FACT:

6. [85] **Average ~~E~~e**nergy bid prices offered by Auction Mechanism Providers were not competitive in the wholesale market.

16. [86] It is reasonable to test targeted corrections and contract amend**ment**s to address the more critical changes to ensure reliability of the Auction Mechanism and improve performance inadequacies.

~~42. [88] Reliability Demand Response Resources are not designed to be used on a regulator basis to address grid reliability needs.~~

~~44. [88] The infrequency of Reliability Demand Response Resources use could lead to difficulties with ensuring accountability.~~

~~45. [88] Reliability resources are not as flexible and useful to the CAISO.~~

48. [89] Our objective for the first step toward improving the accuracy of Qualifying Capacity is to ground estimates of demand response capacity by referencing historical performance data as much as possible **in the month-ahead supply plan** at every state of a resource's development prior to the delivery or showing month.

57. [89] **Month-ahead** Qualifying Capacity estimation methods should be based on resource level aggregated load drop.

73. [91] Demand Response Capacity is contracted and assessed at the aggregate resource level not the individual customer level **but DRAM contracts are not executed at the CAISO resource level**.

76. [91] Prohibiting service account movements **between resources** within a delivery month **~~should~~ is one way to** prevent double payments.

89. [92] **~~Monthly and q~~Q**uarterly performance reports could offer evidence that resources are real.

90. [92] **~~Monthly and q~~Q**uarterly performance reports could be used as a feedback loop to determine whether resources are performing in the market.

95. [93] The framework for the evaluation standards has been established: the six criteria **adopted in D.16-09-056**.

102. [93] The 5-in-10 **and control group** baseline**s** should result in lower implementation costs.

103. [93] We have insufficient information regarding costs to adopt the 5-in-10 **and control group** baseline**s**.

105. [94] Reviewing the 5-in-10 **and control group** baseline**s** simultaneous with the review of the Capacity Bidding Program residential option is a reasonable timeline.

NEW. The current level of funding is approximately $27 million.

NEW. Utility delays in delivering Revenue Quality Meter Data were a factor in delayed Demonstrated Capacity invoices.

NEW. Allowing Demand Response Sellers to utilize a Commission-approved Validation, Editing and Estimation methodology to fill in gaps in utility Revenue Quality Meter Data should reduce utility delays in receiving Demonstrated Capacity invoices.

<u>PROPOSED CONCLUSIONS OF LAW</u>:

12. [96] The Commission should **not** limit the role of Reliability Demand Response Resources and exclude it from the Auction Mechanism.

15. [96] The Commission should adopt a **month-ahead** Qualifying Capacity estimation method that is based on historical data and implementable in a 2019 Auction Mechanism solicitation.

25. [97] The Commission should require ~~**monthly and**~~ quarterly performance reporting for all Auction Mechanism resources.

29. [97] The Commission should review the 5-in-10 **and control group** baseline**s** simultaneous with the review of the Capacity Bidding Program residential option in the mid-cycle review.

<u>PROPOSED ORDERING PARAGRAPHS</u>:

2. [98] The following annual budgets for Demand Response Auction Mechanism solicitations are authorized: in year 2019 - $**11.4**~~**3.5**~~ million each to Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) and $**2.85**~~**1.2**~~ million to San Diego Gas & Electric Company (SDG&E); in years 2020, 2021 and 2022 -- $~~**6**~~ **$12** million each annually to PG&E and SCE and ~~**$2**~~ **$3** million to SDG&E.

4. [99] Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall implement the 2019 Demand Response Auction Mechanism (Auction Mechanism) solicitation using the following schedule:

Schedule for 2019 Auction Mechanism Solicitation with 2020 Deliveries	
Activity	**Date**
Utilities Submit Tier Two Advice Letters with Contract Improvements And Request for Offer Guidelines	August 12, 2019
Commission Approves Advice Letters	September 11, 2019

Utilities Launch Request for Offers for Deliveries Beginning 2020	October ~~11~~ **4**, 2019
Utilities Submit Tier One Advice Letters with Executed Contracts	~~**January 10, 2020**~~ **December 16, 2019**
First Supply Plans Submitted	~~**April**~~ **March** 1, 2020
Deliveries Begin	~~**June**~~ **May** 1, 2020

6. [99] Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall implement the following improvements to the Demand Response Auction Mechanism (Auction Mechanism) for Step One: a) Providing Accurate Qualifying Capacity estimates as further explained in Ordering Paragraph 7; b) Imposing a penalty structure for shortfalls in Demonstrated Capacity as further explained in Ordering Paragraph 9; c) Calculating Demonstrated Capacity on invoices as further explained in Ordering Paragraph 10; d) Establishing invoice deadlines as further explained in Ordering Paragraph 11; e) Replacement of the residential set-aside with a 10 percent set-aside limited to new market entrants; f) elimination of the use of the August bid price cap; ~~**g) Exclusion of the Reliability Demand Response Resources in the Auction Mechanism;**~~ and ~~**h**~~ **g**) Publication of Auction Mechanism contract summaries to include the name of the counterparties, product type, customer class, contracted capacity and contract term.

7. [100] Beginning with the 2019 Demand Response Auction Mechanism solicitation, Demand Response Providers (Providers) shall be required to provide estimates of Qualifying Capacity for a resource by referencing historical performance data. Providers shall provide this estimation **(at the resource level)** ~~**at three stages: a) Submission of a capacity bid into the Auction Mechanism solicitation; b) Submission of the year-ahead resource adequacy plan; and c) Submission of the monthly Supply Plan**~~ **when the monthly Supply Plan has been submitted. The monthly Supply Plan will be reviewed by an independent third party**. Estimates shall be consistent with the guidance provided in Appendix A of this decision. If historical performance data is not available, the Provider shall reference publicly available performance data that best represents the anticipated performance of the resource, while complying with the guidance provided in Appendix A.

11. [101] Demand Response Sellers in the Demand Response Auction Mechanism shall submit Demonstrated Capacity invoices using the following timeline and policies: ~~**a) Once a**~~

~~**Seller receives 95 percent of Revenue Quality Meter Data for a resource's dispatch event, the due date for the Demonstrated Capacity invoice is no later than 30 days after receiving the data; b) If a Seller does not receive 95 percent of Revenue Quality Meter Data for a resource's dispatch event, the Seller may submit a partial invoice for resources with available data no later than 30 days after receiving the data; and c)**~~ **a) The due date for the Demonstrated Capacity invoice is no later than 30 days after the end of the delivery month; b) To the extent the IOU has not provided 100% of the Revenue Quality Meter Data, the Demand Response Seller may utilize a Commission-approved Validation, Editing and Estimation methodology in place of the missing Revenue Quality Meter Data; c) Should the final Revenue Quality Meter Data indicate an overpayment to the Demand Response Seller, the Utility is prohibited from recovering the overpayment; d) Should the final Revenue Quality Meter Data indicate an underpayment to the Seller, the Seller may re-invoice for the full payment; and e)** Demonstrated Capacity invoicing is at the resource level.

12. [102] The Commission's Energy Division is authorized to facilitate a series of working group meetings to address the following issues: 1) ~~**Replacement for August Bid Price Cap; 2) Minimum Dispatch Hours; 3)**~~ Revenue Quality Meter Data Penalty and Contract Remedy; **~~4~~ 2**) Contract Partitioning and Reassignment; **~~5~~ 3**) Bid Fees; **~~6~~ 4**) Guidelines for Utility Audits and Withholding Payments; **~~7~~ 5**) Data Authorization, Collection and Protection; and **~~8~~ 6**) CAISO Registration and Meter Reprogramming**, and 7) Dispute Resolution Process**. The working group shall file a report on its proposals to address these **~~eight~~ seven** issues. We adopt the procedural schedule for the working group as shown in the following table:

Activity	**Deadline**
Working Group Conference Call Phone: 866-832-3002 Passcode: 7708052# Time: 10:00 a.m. to 4:00 p.m.	July 15, 2019
Working Group Meeting	July 22, 2019
Working Group Meeting	July 23, 2019
Working Group Meeting	July 29, 2019
Working Group Meeting	July 30, 2019
Working Group Files Report	August 9, 2019
Comments on Working Group Report	August 23, 2019

14. [102] Demand Response Auction Mechanism Sellers shall provide the Commission's Energy Division a ~~**monthly**~~ **quarterly** performance report for all Demand Response Auction Mechanism resources. The ~~**monthly**~~ **quarterly** performance report shall include, but not be limited to, bid and performance data for the showing month, resource characteristics and dispatch trigger, and other aggregation details. The report shall be due 30 days after the end of the showing month. On a quarterly basis, the independent consultant will anonymize and aggregate the monthly reports into a public Demand Response Auction Mechanism Performance Summary. Energy Division is authorized to work with parties to develop a standardized format for the Seller's monthly report.

15. [103] Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) are authorized to contract with a consultant to evaluate the continuation of the Demand Response Auction Mechanism (Auction Mechanism) and assist the Commission's Energy Division in monitoring the Auction Mechanism. The Energy Division is authorized to manage the selection of the consultant and the evaluation study. The Energy Division is delegated the authority to make the final selection of the consultant. The evaluation shall include performance of delivery years 2018 through 2020, and the solicitation process for years 2019, 2020 and 2021. The Utilities and Demand Response Auction Mechanism Sellers and Providers are directed to cooperate with the consultant in terms of providing information and date. The consultant shall work with the Utility Auction Mechanism Contract Manager, and the Independent Evaluator to assist the Energy Division, as needed, to monitor the Auction Mechanism and review monthly reports. The consultant shall provide a preliminary evaluation report to the Energy Division no later than September 1, 2021. A final evaluation report shall be made available to all parties no later than December 1, 2021 for review. We authorize a budget of $2.8 million to perform the evaluation. **This funding is incremental to the $27 million annual budget for Demand Response Auction Mechanism solicitations authorized in Ordering Paragraph 2.**

17. [104] Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) ~~**shall include a proposal in their 2020 demand response portfolio mid-cycle advice letter filing, for implementing the 5-in-10**~~

~~baseline~~ **submit a proposal for implementing the 5-in-10 baseline in a Tier 1 advice letter on August 9, 2019**. The proposal shall include estimated costs and a timeline. If the implementation costs are less than the benefits of the improved baseline, Energy Division is authorized to recommend adoption in the resolution addressing the mid-cycle review.

NEW. **The 2019 Demand Response Auction Mechanism solicitation shall be for System and Flexible Resource Adequacy products and the 2020-2022 solicitations shall be for System, Local and Flexible Resource Adequacy products.**

NEW. The Utilities shall submit Tier One advice letters with executed contracts for the 2019-2022 solicitations.