BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	Rulemaking 20-11-003 (Filed November 19, 2020)

REPLY BRIEF OF THE JOINT PARTIES ON PHASE 2 ISSUES

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California Efficiency + Demand Management Council ("the Council"), ecobee, Inc. ("ecobee"), Leapfrog Power, Inc. ("Leap"), and Oracle ("the Joint Parties") respectfully submit this Reply Brief on Phase 2 Issues in Rulemaking (R.) 20-11-003 (Emergency Reliability). In this Rulemaking, the Commission seeks to establish an expedited process to ensure there is adequate supply and demand management to achieve electrical system reliability in 2022 and 2023. The Joint Parties' Reply Brief is timely filed and served pursuant to the Commission's Rules of Practice and Procedure, Rule 13.12 and the Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2 ("Amended Scoping Memo"), dated August 10, 2021.

I.
THE JOINT PARTIES' ARGUMENTS REGARDING THE DEMAND RESPONSE AUCTION MECHANISM ("DRAM")

A. The Commission should approve the proposals to improve the reliability of DRAM resources.

The Joint Parties and Joint Demand Response Parties ("Joint DR Parties")[1] have put forth significant proposals toward addressing the most serious concern expressed by several parties with regard to the expectation that contracted DRAM resources are delivered. The Joint Parties reiterate its proposal that the Commission, retroactive to the already-completed 2022 DRAM auction, either 1) establish an interim penalty structure to ensure that delivered capacity is consistent with contracted capacity, or 2) issue a ruling directing parties to submit penalty proposals as supplemental testimony in this proceeding.[2] In addition, the Joint Parties echo the Joint DR Parties' support of the Voltus proposal to pilot a collateralization method to enforce

[1] The Joint DR Parties are comprised of CPower and Enel X North America, Inc.
[2] Opening Phase 2 Prepared Testimony of the Joint Parties, submitted on September 1, 2021 ("Exhibit ("Ex.") Joint Parties-01"), at p. 8, line 3 through p. 10, line 6.

delivery on DRAM contracts.[3] The Joint Parties take seriously the Commission's and other parties' concerns regarding the reliability of DRAM resources and urge the Commission to take these two actions to address them.

B. Investor-Owned Utilities ("IOUs") are not required to spend 100% of DRAM budget – they are only required to procure cost-effective DRAM resources.

Throughout this phase of the proceeding, several parties have argued against approval of an expanded 2022 and 2023 DRAM budget for various reasons.[4] The Joint Parties have addressed all of these arguments with the exception of the contention that DRAM resources are not cost-effective and that the IOUs must spend to the limit of their budget. As an example, San Diego Gas & Electric ("SDG&E") argues that the "public interest is not served by a requirement to procure DR through the DRAM at prices, and up to its budget cap, that may not be competitive with other resources."[5] Similarly, Southern California Edison ("SCE") argues that "a supplemental auction may, in fact, result in higher costs to customers for no additional capacity."[6]

These statements are highly misleading on two counts. First, the Commission established an explicit cost-effectiveness requirement in Decision ("D.") 19-07-009 and updated in D.19-12-040 that is based on the Commission-approved Long-Run Avoided Cost of Capacity ("LRAC") above which IOUs may not accept DRAM bids.[7] Second, because of this auction bid constraint, IOUs are not <u>required</u> to procure up to their full DRAM budget if an equivalent amount of cost-effective DRAM bids have not been submitted. Should the Commission approve a supplemental 2022 DRAM auction and an expanded 2023 DRAM budget, these same cost-effectiveness requirements would continue to be in effect. Therefore, the Commission can be assured that only cost-effective DRAM resources, as defined by the Commission's own decision, would be procured.

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[3] Joint DR Parties Opening Brief, at pp. 23-24.

[4] *See, e.g.,* Pacific Gas and Electric ("PG&E") Opening Brief, at pp. 16-18; Southern California Edison ("SCE") Opening Brief, at pp. 42-44; San Diego Gas & Electric ("SDG&E") Opening Brief, at pp. 29-30; Public Advocates Office Opening Brief, at pp. 11-14; and California Large Energy Consumers Association ("CLECA") Opening Brief, at pp. 10-12.

[5] SDG&E Opening Brief, at p. 29.

[6] SCE Opening brief, at p. 43.

[7] D.19-07-009 is the Decision Addressing Auction Mechanism, Baselines, and Auto Demand Response for Battery Storage, issued on July 12, 2019 in Application (A.) 17-01-012, et al., at p. 108 (Ordering Paragraph 5) and D.19-12-040 is the Decision Refining the Demand Response Auction Mechanism, issued on December 23, 2019 in A.17-01-012, et al., at p. 87 (Finding of Fact 65).

C. The number of DRAM bidders has no bearing on an expanded DRAM budget.

Another common misconception being propagated among some parties in this proceeding is that fewer DRAM bidders in recent auctions can only be concluded to mean that the 2022 and 2023 DRAM budget should not be expanded. SDG&E observes less capacity being offered by fewer bidders and suggests this justifies Commission rejection of an expanded DRAM.[8] Pacific Gas and Electric ("PG&E") makes a similar argument regarding commitment and delivery of capacity in DRAM.[9] Both SDG&E and PG&E ignore the market fundamentals within its own service area when making this assessment.

Furthermore, with all due respect to SDG&E, it is the size of SDG&E's market and DRAM budget that is largely behind lower interest among DR providers ("DRPs") in its service area. SDG&E's annual DRAM budget is $2 million so, with such a small DRAM budget, the business proposition does not exist for most DRPs to make the investment to conduct an enrollment campaign in its service area, especially for non-residential customers. Furthermore, there is simply a dearth of suitable non-residential customers in SDG&E's service area to justify competing with even a handful of DRPs to have confidence that enough customers can be cobbled together a year into the future to deliver on a DRAM contract.

In fact, SDG&E has made similar arguments as the Joint Parties make here in prior proceedings when addressing shortcomings with its DR program cost effectiveness. In its Rebuttal Testimony in A.17-01-012 et al., SDG&E Witness Mantz states that SDG&E cost-effectiveness challenges with its own DR programs are due to 1) a lack of an industrial customer base and corresponding load, and 2) fewer total MWs relative to administrative costs compared to other IOUs.[10] These same reasons translate into diminished opportunities for DRAM providers as well. However, in spite of such a small budget, SDG&E has in fact managed to procure growing amounts of DRAM capacity. In the 2022 DRAM, SDG&E procured 28 MW which was an increase of 5 MW compared to the 2021 DRAM, a 21% increase. So, lower participation should not impact the Commission's consideration of expanding the DRAM budget.

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[8] SDG&E Opening Brief, at pp. 29-30.
[9] PG&E Opening Brief, at p. 16.
[10] SDG&E Rebuttal Testimony submitted in A.17-01-012, et al., at p. EBM-3, lines 3-6.

II.
THE COMMISSION SHOULD MAINTAIN THE BASE INTERRUPTIBLE PROGRAM ("BIP") AS A SUPPLY-SIDE PROGRAM

California Large Energy Consumers Association ("CLECA") and SCE recommend the Commission declare all Reliability Demand Response Resources ("RDRR") as Load Modifying Resources pursuant to D.14-03-026, which would eliminate any requirement that they participate in the California Independent System Operator ("CAISO") market due to recent unspecified CAISO tariff changes that will increase the difficulty of dispatching RDRRs, including BIP.[11] The Commission should reject this proposal as it pertains to BIP. Neither party has specified the offending tariff revision so it is difficult to verify their claims. The Joint Parties also point out that PG&E, with far more sub-Load Aggregation Points ("subLAPs") than SCE, has not made a similar recommendation, so SCE's concerns may simply be due to an issue with their own operations. Finally, SCE has already explained that it intends to deal with the perceived risks from the CAISO's tariff revisions by putting BIP resources on outage in real time and instead managing its dispatches manually during emergency events. So, with a solution already in place, sufficient justification does not exist for removing BIP from the CAISO market.[12]

III.
THE COMMISSION SHOULD NOT ADOPT A CAPACITY BIDDING PROGRAM ("CBP") BID PRICE CAP OR A GENERAL BID PRICE CAP ON PROXY DEMAND RESPONSE ("PDR")

The Joint Parties continue to oppose a bid price cap for all DR programs, including PG&E's CBP Elect and CBP Elect+ for 2022 and 2023, as well as CLECA's proposal for a lower bid cap on Proxy Demand Resources. This will create unnecessary distortions to the wholesale energy market, which is outside the Commission's jurisdiction and will only lead to less DR participation which is the direct opposite of the outcome that the Commission is seeking in this proceeding.

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[11] Reply Testimony of Catherine Yap and Paul Nelson on behalf of the California Large Energy Consumers Association, submitted on September 10, 2021 ("Ex. CLECA Reply Testimony"), at p. 5, line 13 through p. 7, line 11 and SCE Opening Brief, at pp. 35-36.
[12] SCE Opening Brief, at p. 36.

According to PG&E, all of its nominated CBP resources would have been dispatched if they had bid $650/MWh.[13] Providers of any type of market-integrated dispatchable resources, be they fossil generators, hydro-electric plants, or demand response, have the right to submit energy market bids that reflect their opportunity costs. PG&E is a strong adherent to this practice with its hydroelectric fleet and the Joint Parties suspect that PG&E would be highly resistant to having an artificial bid cap imposed on these resources.

Furthermore, the notion of a bid cap in this instance appears to be a red herring in that it ignores the question of why, when the CAISO was requesting IOUs to implement involuntary load shedding in 2020 at a massive economic cost to the state's homes and businesses, those DR resources with bids near or at the CAISO's FERC-approved bid cap were never dispatched. Rather than distorting the CAISO's energy market with an artificial bid cap that does not reflect customer opportunity costs and will only reduce the amount of CBP capacity, the Commission should urge the CAISO to fix the shortcomings of its market that allowed LSEs to under-schedule load by 2,000 on August 14 and 15, 2020.[14]

For similar reasons, the Commission should reject CLECA's recommendation that a PDR bid cap be adopted at a lower price than the RDRR minimum bid price.[15] CLECA's effort to minimize BIP events at the expense of other types of DR is inappropriate given the high payments already received by BIP participants. There is no justifiable reason why BIP and PDRs in general should be subject to different bid limitations. Therefore, the Commission should reject this proposal.

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[13] Pacific Gas and Electric Company Emergency Reliability Order Instituting Rulemaking Opening Testimony, submitted on September 1, 2021 ("Ex. PG&E Opening Testimony"), at p. 4-1, lines 13-25 and PG&E Opening Brief, at p. 11.

[14] Final Root Cause Analysis, at pp. 61-62.

[15] Testimony of Catherine Yap and Paul Nelson on behalf of the California Large Energy Consumers Association, submitted on September 1, 2021 ("Ex. CLECA Opening Testimony"), at p. 8, lines 8-12.

IV.
THE JOINT PARTIES' ARGUMENTS REGARDING THE EMERGENCY LOAD REDUCTION PROGRAM ("ELRP")

A. Residential customers should not be defaulted into the ELRP if financial incentives are offered, and Automation Service Providers Must Be Compensated for Facilitating Broad Automated Load Reductions During System Emergencies.

As Grid Alternatives expresses, there is broad support among parties for residential participation in the ELRP.[16] However, as the Joint Parties and other parties have repeatedly warned, it is critical that residential customers not be defaulted to the ELRP if they will be provided a financial incentive to avoid.[17] The Joint Parties support defaulting customers only if residential ELRP will be a behavioral DR ("BDR") program (i.e., no financial compensation) and if the IOUs' respective processes allow for a seamless transition by ELRP participants to enroll in a different DR program. If the Commission adopts the Energy Division proposal and residential customers are defaulted into the ELRP, the Commission must clarify how automation service providers are compensated for facilitating a broad automated response to Flex Alerts for residential customers, something the California Energy Commission ("CEC") hope to facilitate through its MIDAS system. Any expectation on the part of the Commission that third parties will play a role in notifying or directly dispatching residential ELRP participants should be linked to compensation through Emergency Agreements or by opening Group B to non-DR customers.

B. The Commission should not require Group B ELRP participants to nominate an estimated target load reduction and the Commission should open Group B to non-DR customers.

The Joint Parties urge the Commission not to adopt SCE's proposal that ELRP Group B participants nominate an estimated target load reduction.[18] The CAISO supports this proposal and proposes an amendment to 1) explain how the anticipated load drop from ELRP Group B customers was calculated, and 2) specify each customer's or at least their subLAP.[19]

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[16] Grid Alternatives Opening Brief, at p. 2 and Public Advocates Office Opening Brief, at p.
[17] *See, e.g.,* Opening Phase 2 Prepared Testimony of the Joint Parties, submitted on September 1, 2021 ("Ex. Joint DR Parties-01"), at p. 9, lines 23-28 and Phase 2 – Reliability for 2022-23 – Update: Opening Prepared Testimony of Joint Demand Response Parties, submitted on September 1, 2021 ("Ex. JDRP-3"), at p. 26, lines 14-21.
[18] Direct Testimony of Southern California Edison Company – Phase 2, submitted on September 1, 2021 ("Ex. SCE-04"), at p. 38, lines 12-20.
[19] CAISO Opening Brief, at p. 14.

The ELRP is a voluntary, best-efforts program so any nomination estimates will be extremely inaccurate and therefore will have little-to-no practical value. Ironically, the CAISO's recommendation to adopt an ELRP Group B load nomination requirement is immediately followed by a recommendation that ELRP not have a capacity value. The Commission should only require customers to nominate load reductions for capacity-based DR programs, just as they are for the CBP. However, absent a capacity value (and associated capacity payment) and associated enforcement mechanism, load nominations should not be required.

Unfortunately, the CAISO's proposed amendments would only increase the effort and cost to DRPs to participate in the ELRP. The CAISO's proposal that IOUs and DRPs justify their load nomination to the CAISO would be a major waste of time for all parties involved and would risk forcing DRPs to share competitive and proprietary information. Even requesting customer zip codes or subLAPs seems like a bridge too far by raising the cost of participating in this program.

One of the selling points to DRPs and customers for participating in the ELRP is its comparative administrative simplicity relative to market-integrated DR programs. The Commission should avoid the urge to unnecessarily complicate it with new requirements that may be "nice to have" but ultimately provide little to no additional value.

As a related issue, the Joint Parties reiterate their recommendation that the Commission open Group B to non-DR customers. This will allow DRPs to tap into currently under-utilized customers that are not currently participating in DR programs. The Joint Parties expect that the ELRP would be a springboard for some of these customers to enroll in other DR programs in the future.

V.
IMPLEMENTATION OF TECHNOLOGY INCENTIVES SHOULD BE OPENED TO THIRD PARTIES WITH MARKET-INTEGRATED DR PROGRAMS

The Joint Parties and OhmConnect, Inc. ("OhmConnect") have made compelling arguments in favor of third-party implementation of technology incentives.[20] The IOUs have consistently claimed that they, and only they, are in the best position to implement these programs. However, the Joint Parties and OhmConnect have demonstrated that this proposal

[20] Ex. Joint Parties-01, at p. 20, line 7 through p. 25, line 16 and Opening Testimony of Maria Belenky on behalf of OhmConnect, Inc., submitted on September 1, 2021 ("Ex. OhmConnect Opening Testimony'), at p. 8, line 18 through p. 10, line 10.

would result in greater uptake of technology incentives, provide verification to the local IOU that customers receiving incentives have enrolled in a DR program, and hold ratepayers free from any financial risk. The Commission should adopt the Joint Parties proposal and initiate a working group process to develop the parameters of such a program.

VI.
SMART THERMOSTAT INCENTIVES SHOULD NOT BE LIMITED TO CERTAIN CLIMATE ZONES

The Joint Parties and Google have demonstrated why smart thermostat incentive programs should not be limited to certain climate zones. Using the combined EE-DR cost-effectiveness test, accounting for thermostat optimization savings and requiring pre-enrollment in DR programs with smart thermostat incentives will render the devices cost-effective throughout the state, so limiting these incentives to certain climate zones would be counter-productive. The IOU proposals to expand smart thermostat incentive programs should be approved, and the Commission should order that any bring-your-own-device program or emergency program does not require customers to enter their utility account number to complete enrollment to prevent unnecessary attrition when customer validation can be accomplished using name and address.

VII.
THE DR PROCUREMENT CAP SHOULD BE RAISED, ELIMINATED, OR SUSPENDED

The Commission should grant the relief requested by the Joint Parties and The Utility Reform Network ("TURN") and address the 8.3% DR procurement cap in such a way as to eliminate its potential to create a barrier to additional DR procurement.[21] The Joint Parties have shown that it effectively caps DR procurement at a much lower level by rendering LSEs' headroom unusable by any other LSE and makes third-party DR subordinate to IOU DR programs which is directly contrary to approved Commission policy. The Commission should either 1) apply the current 8.3% cap at the system level (eliminating the per-LSE cap), 2) apply the cap to unallocated DR only, or 3) increase the cap to 16.6%.

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[21] Joint Parties Opening Brief, at p. 11 and TURN Opening Brief, at p. 8.

VII.
THE COMMISSION SHOULD APPROVE NEW LOAD-SHAPING DR PROGRAMS

Though the Commission's focus is rightfully on addressing resource needs to ensure reliability in 2022 and 2023, when practical, it should also keep an eye on innovation within the DR space. To that end, the Commission should approve Marin Clean Energy's ("MCE") Peak FLEXmarket program and Recurve's Demand FLEXmarket program.

The Joint Parties echo the MCE statement that it is critical for LSEs to provide DR on an equal footing with IOUs.[22] The Commission should approve the requested funding for MCE's Peak FLEXmarket program. It is a highly innovative approach to delivering shaped load curves by delivering a combination of baseload energy efficiency savings, regular load shifting, and periodic load shedding during acute system needs. As MCE has stated, the program would be funded by approved energy efficiency budget that has gone unused. Perhaps this can serve as a model for, as Recurve puts it, to "create a pathway for CCAs, IOUs, or other non-LSE program administrators to implement a market access model to enable resources in 2022 and 2023."[23] The Joint Parties continue to also support dynamic price models for providers who want to focus on real-time electricity price hedging, but the approach MCE proposes is a substantial step down that road.

Similar to MCE's Peak FLEXmarket program, the Commission should also adopt Recurve's Demand FLEXmarket program as a pilot program for the three IOUs. This could create some preliminary momentum and lessons learned with load-shifting programs with an eye toward what the Joint Parties expect to be a UNIDE proceeding.

VIII.
CONCLUSION

The Joint Parties respectfully recommends that the Commission adopt the Joint Parties' recommended proposals contained in its Opening Brief and this Reply Brief.

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[22] MCE Opening Brief, at p. 7.
[23] Recurve Opening Brief, at p. 2.

Respectfully submitted,

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