Docket No.: R.20-11-003

Exhibit No.:

Date: September 10, 2021

Witness: Jin Noh

REPLY TESTIMONY OF JIN NOH
ON BEHALF OF THE CALIFORNIA ENERGY STORAGE ALLIANCE

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Q: Please state your name and business address.

A: My name is Jin Noh. I am Policy Director of the California Energy Storage Alliance ("CESA"). My business address is David Brower Center, 2150 Allston Way, Suite 400, Berkeley, CA 94704.

Q: Please summarize your professional and educational background.

A: In my capacity as Policy Director, I manage CESA's engagements at the California Public Utilities Commission ("Commission"), California Independent System Operator ("CAISO"), California Energy Commission ("CEC"), California Legislature, Federal Regulatory Commission ("FERC"), and other agencies. I have more than 6 years of experience in policy and regulatory work at these agencies. I hold a Bachelor of Arts in Public Policy Studies and Economics from Duke University and a Master's in Public Policy ("MPP") from the University of California, Berkeley.

Q: Have you ever testified before this Commission?

A: Yes.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of CESA. Founded in 2009, CESA is a non-profit membership-based advocacy group committed to advancing the role of energy storage in the electric power sector through policy, education, outreach, and research. CESA's mission is to make energy storage a mainstream energy resource that accelerates the adoption of renewable energy and promotes a more efficient, reliable, affordable, and secure electric power system for all Californians. As a technology-neutral group that supports all business models for deployment of energy storage resources, CESA's membership includes technology manufacturers, project developers, system integrators, consulting firms, and other clean tech industry leaders.

Q: What is the purpose of your testimony?

A: The purpose of this reply testimony is to provide our responses to various comments and proposals submitted by other parties to address Summer 2022 and 2023 emergency reliability needs. In opening testimony on September 1, 2021, we focused our proposal on the design, structure, and operations of a new Emergency Load Reduction Program ("ELRP") that incentivizes the procurement of new, incremental behind-the-meter ("BTM") resource capacity outside of the Resource Adequacy ("RA") framework to deliver fast, frequently dispatchable, and/or permanent demand response ("DR") including exports during heat-storm events. In addition to our ELRP proposal, we offer our recommendations around: the consideration of expedited Integrated Resource Plan ("IRP") procurement; the role of energy-only ("EO") energy storage procurement, contracting, and operations; various interconnection strategies; modifications to various DR programs, particularly those related to the Demand Response Auction Mechanism ("DRAM"); and the electric vehicle ("EV") and vehicle-grid integration ("VGI") aggregation pilot. CESA does not touch upon every topic or proposal raised, but we address various parties' testimonies regarding the analysis of need, proposed procurement and penalty mechanisms, and key themes regarding recommendations for DR and distributed energy resource ("DER") programs.

I. Introduction

A wide range of proposals, recommendations, and comments were submitted in Phase 2 testimony, but the vast majority of parties agree that the Commission is smartly considering cost-effective and least-regrets strategies to address the risk of system capacity shortfalls in the face of extreme weather events induced by climate change (*e.g.*, drought, heat waves, wildfires). Ideally, the state would not be in this situation of perpetual shortfalls with the need to rapidly deploy clean energy and energy storage projects with very compressed lead times, but the Commission is smartly considering and soliciting a wide range of proposals to identify the least-regrets strategies.

The immediate task ahead will be in culling the list of proposals and recommendations to ones that support the identified needs in this proceeding, but also serve as a launching pad to position resources like energy storage to be quickly deployed and smartly dispatched for reliability purposes, potentially persisting beyond the immediate term. In other words, even if certain proposals or recommendations are adopted as an interim measure to address emergency needs, certain strategies may be beneficial to maintain to scale the level of clean energy, energy storage, and DER deployment needed to meet our long-term goals and to serve as a tested emergency mitigation measure for future emergencies. As such, CESA encourages the Commission to adopt many, if not all, of our proposals detailed in our opening testimony. If further refinement is needed, CESA is willing and eager to provide the necessary and complete details for any of our proposals to support its adoption.

II. Summary of Recommendations

After reviewing parties' testimonies, CESA offers the following key responses:

- While the assumptions regarding hydro resources in the Draft 2022 Net-Short Analysis are too conservative, they should reflect recent directives by the State Water Resources Control Board ("SWRCB").
- Integrated Resource Plan ("IRP") penalties are unnecessary and should not be adopted, nor should conditional penalties that require demonstration of force majeure events.
- The use of the Central Procurement Entity ("CPE") authority requires further clarification and justification, but if used, it should affirm long-term contracts for new preferred and energy storage resources.
- Utility-owned storage ("UOS") should be pursued to support emergency reliability needs, but the IOUs should also broaden the focus to third-party-owned storage solutions that can meet Summer 2022/2023 commercial online dates.
- Hybridization of battery storage to sites where there is excess interconnection capacity or where hybridization can free up and improve the emissions profile of the gas portfolio should be prioritized.
- Pre-RA deliveries or proxy RA should be allowed to support near-term reliability where conditions and locations allow.
- Timely resolution of paired storage eligibility in the Renewable Market Adjusting Tariff ("ReMAT") and Public Utility Regulatory Policies Act ("PURPA") Standard Offer Contract ("SOC") can support near-term reliability.
- Capacity or reservation payment structures are needed to drive more meaningful and robust participation in the ELRP.
- ELRP features should generally be consistent across customer groups, including around compensation and dual participation rules.

- Various IOU and CCA pilots should be approved and funded, with consideration of how they can be incorporated into planning and operations and eventually assessed for scaling potential.
- The shared concerns with automatic enrollment point to not adopting staff's proposal to automatically enroll all residential customers in ELRP.
- The EV/VGI Aggregation Pilot should be approved given their market and technical potential, with the minimum dispatch requirement providing financial certainty and advancing VGI learning objectives.

III. Analysis of Need

CESA appreciates the thorough comments offered by parties with regards to the Draft 2022 Net-Short Analysis, the basis by which the Commission, with the support of the CEC, has sought to approximate the potential supply shortfall for Summer 2022. A significant share of parties found limited value in a deterministic stack analysis with assumptions largely disconnected from other planning venues, such as those for RA or the IRP proceedings. Importantly, CESA found a significant number of parties advise against the Commission determining incremental procurement needs without a loss-of-load expectation ("LOLE") study that would, through a stochastic modeling process, determine the likelihood and magnitude of potential shortfalls with increased certainty.

In this context, CESA offers a single recommendation below to improve this expedited analysis in order to better estimate the total need and identify no-regrets actions. Nevertheless, CESA cautions against the application of recommendations that would have significant ramifications without deeper analysis in the appropriate proceeding, such as the CAISO's recommendation to establish RA requirements for the net-load peak, or the blanket retention of all existing generation capacity. These important questions are being taken up in RA restructuring proposals in R.19-11-009 as well as upon the completion of important reliability studies being conducted by the CEC.

A. While the assumptions regarding hydro resources in the Draft 2022 Net-Short Analysis are too conservative, they should reflect recent directives by the State Water Resources Control Board.

Several of the critiques of the Draft 2022 Net-Short Analysis focused on its deterministic approach and its use of overly conservative demand assumptions, particularly with regards to the planning reserve margin ("PRM") and the variance of demand. The California Community Choice Association ("CalCCA") highlighted the large range of potential shortfalls as evidence of the limits of stack analyses. Moreover, CalCCA, just like the Union of Concerned Scientists ("UCS"), requested the Commission share more detailed information regarding the resources and assumptions used in the Draft 2022 Net-Short Analysis, highlighting the difficulty to assess the likelihood of a supply shortfall with the information that is currently available. Importantly, UCS and Southern California Edison ("SCE"), among other parties, urged the Commission to reconsider some of the supply-side assumptions used in this analysis and use more thorough LOLE methodologies to assess the likelihood and magnitude of potential shortfalls.

Moreover, SCE highlighted the inconsistent use of demand- and supply-side assumptions in the Draft 2022 Net-Short Analysis. For example, SCE notes that the 1.5 GW derate applied to hydroelectric generation to signify the possibility of drought conditions extending into 2022 is unwarranted since the qualifying capacity ("QC") methodology for hydro already reflects their capacity availability through drought as it generates monthly values based on the previous ten years of historical offered capacity.[1] Notably, the QC methodology to which SCE refers even takes into account average and outlier generation conditions. For each month of the 10-year period, staff generates a median (50% exceedance) and a 10% exceedance value based on the capacity bid or self-scheduled into the CAISO market discounting mechanical derates; to determine monthly QC values, the median

[1] SCE Opening Testimony at A-2.

value is weighted 80% and the 10% exceedance value is weighted 20%.[2] Given the formulation of this QC calculation, SCE argues that the 1,500 MW derate is unnecessary and should be removed.

CESA agrees with SCE that the 1.5 GW derate, despite resulting from the Commission's intention to better represent current drought conditions in the Draft 2022 Net-Short Analysis, must be reevaluated in light of hydro's applicable QC methodology. That being said, while SCE's observation that the current dispatchable hydro QC methodology already seeks to capture recent average and outlier conditions is correct, it is also important to note that the activities of dispatchable hydro generators are affected by regulations beyond those issued by the Commission, such as the curtailment orders issued on August 2021 by the SWRCB. Currently, curtailment orders are in effect for the Russian River and the Sacramento-San Joaquin Delta, with other curtailment orders being considered.[3] As of now, certain non-consumptive uses that do not decrease downstream flows may continue despite these curtailment orders.[4] Nevertheless, this exception could be modified if drought conditions fail to improve.

In sum, while CESA agrees with SCE's questions about the 1.5 GW derate, we encourage the Commission and the CEC to revise this assumption taking into consideration if and how curtailment orders issued by the SWRCB could affect hydroelectric output, as requirements such as these are complex to consider using only the QC methodology. This assumption could potentially influence the underlying needs determination for any incremental or accelerated procurement for Summer 2022/2023 needs.

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[2] CPUC *2020 Qualifying Capacity Methodology Manual* at 18.
[3] *See* SWRCB, *Drought Orders, Proclamations, Notices, and Letters*, updated August 10, 2021 at https://www.waterboards.ca.gov/drought/drought_orders_proclamations.html
[4] SWRCB, *"Curtailment Orders in the Russian River Watershed – Fact Sheet",* 2021, at 5. https://www.waterboards.ca.gov/drought/russian_river/docs/FAQ_Russian_River_Curtailment_Orders_08-02-21.pdf

IV. Expedited Generation and Energy Storage Procurement, Contracting, and Other Processes

CESA detailed in opening testimony how timely procurement orders and contract approvals are important to bring on incremental in-front-of-the-meter ("IFOM") energy storage under compressed timeframes in support of residual, unmet needs for Summers 2022 and 2023. Many parties, including the investor-owned utilities ("IOUs") and many non-IOU load-serving entities ("LSEs"), appear to similarly understand these project development risks. Given these short lead times and the emergency nature of these reliability risks over the next two years, CESA reiterates our calls to allow for some flexibility in the end-to-end process for energy storage deployment in the near term and move toward streamlined and expedited processes in the long term to support the unprecedented buildout of this resource type projected over the next 20 or more years. Furthermore, many parties detailed certain opportunities to increase the supply of proposals that CESA did not touch upon in opening testimony, to which we respond below and offer our recommendations.

A. IRP penalties are unnecessary and should not be adopted, nor should conditional penalties that require demonstration of force majeure events.

Many parties overwhelmingly oppose LSE penalties for failing to meet COD deadlines for IRP procurement requirements, citing a range of reasons such as the chilling effects on procurement, the retroactive nature of the penalties, and various factors that are outside the control of the buyer or seller.[5] Western Trading Power Forum ("WPTF") aptly explains that the Commission already has the authority to assess fines and take measures against non-compliance.[6] As explained in CESA's opening testimony, bilateral contracts between buyers and sellers also recognize the importance of complying with procurement orders, which are reflected in negotiated contract provisions around initial delivery

[5] LS Power Opening Testimony at 7; IEP Opening Testimony at 3; SDG&E Opening Testimony (Comments on Energy Division Staff Concept Paper, Witnesses Jeff DeTuri and Habibou Maiga) at 6-7; CalCCA Opening Testimony at 7-8; PG&E Opening Testimony Chapter 9 at 1-2; SCE Opening Testimony at 76-77.

[6] WPTF Opening Testimony at 2

dates and penalties for delay (*e.g.*, day-for-day $/kW delays). There is thus a near-consensus among parties, including both buyers and sellers, who oppose the IRP penalties proposal. As such, CESA reiterates our recommendation to not adopt this proposal.

However, in our review, Cal Advocates was the only party in support of an IRP procurement penalty mechanism, citing the reduced prospect of ratepayer costs resulting from backstop procurement and the potential for free ridership by deficient LSEs.[7] Among the two options considered in the staff concept paper, Cal Advocates recommended adoption of a $10 per kilowatt-month capacity-based penalty to account for differences in LSE load share and size, along with a ten-month grace period for delayed projects to come online that accounts for the period at the beginning of the summer when incremental resources are needed. If unable to meet the commercial online date pursuant to D.19-11-016, an LSE would have to submit a Tier 1 advice letter to seek a penalty waiver in case of force majeure events (*e.g.*, pandemic-related delays).[8]

Despite Cal Advocates' consideration of force majeure events, CESA opposes this proposal because these force majeure provisions are already (typically) included in negotiated contracts between sellers and buyers, making such a penalty mechanism duplicative and unnecessary. Even if a penalty waivers process is in place, a separate Commission-established penalty mechanism will only serve to add another layer of regulatory process and uncertainty as to whether the Commission will grant the waiver, when in fact the negotiated contract is in place to cover and specify the conditions that qualify as force majeure events. Counter to Cal Advocates' intent to reduce ratepayer costs, this injection of additional and duplicative regulatory process and uncertainty will lead to higher long-run ratepayer costs in the form of reduced or chilled market participation in current and future resource solicitations and/or higher contract prices to account for regulatory risks.

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[7] Cal Advocates Opening Testimony Chapter 4 at 1-2.
[8] *Ibid* at 2-3.

Furthermore, CESA echoes many parties' concerns that there are many factors beyond just force majeure events that are outside the control of the project developer. Resource developers universally express concerns with the delay in the interconnection process, particularly as they relate to transmission upgrade construction timelines.[9] Similarly, it is unfair to penalize LSEs and, by extension, resource developers for events such as "superclusters" that resulted from pent-up market demand for new resource procurement but do not fall within the typical definition of force majeure events. The CAISO is currently experiencing a record volume of interconnection requests in Queue Cluster ("QC") 14, which has led to a one-year delay in the typical cluster study process and also impacted the completion of the process for all previous QCs.

Taken together, Cal Advocates' proposed IRP penalty mechanism, even with grace periods and waiver processes, should not be adopted for the significant levels of uncertainty imposed on LSEs and developers, resulting in higher ratepayer costs.

B. The use of the CPE authority requires further clarification and justification, but if used, it should affirm long-term contracts for new preferred and energy storage resources.

PG&E requested that the Commission authorize PG&E, in its CPE function, to be able to procure preferred and/or energy storage resources for Local RA in qualifying local capacity areas that can come online by Summer 2022 or 2023, which would then be submitted to the Commission via a Tier 1 advice letter process consistent with the previous summer emergency reliability procurement

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[9] *See, e.g.,* MRC Opening Testimony at 9; SEIA Opening Testimony at 12-13; and ACP-CA Opening Testimony at 5-6. To overcome these bottlenecks, parties recommended approaches that entail the Commission taking a more active role in enforcing transparency and accountability regarding these timelines, or even creating a financial incentive to ensure timely completion of necessary upgrades (e.g., impact on IOU return on equity). To bring online the significant amounts of new and preferred resource capacity to support emergency reliability needs as well as to advance the state's decarbonization goals, the Commission must apply a concerted focus on how to streamline and expedite interconnection and transmission upgrade construction timelines

order, D.21-03-056.[10] This contract approval process would be in contrast to the Tier 3 advice letter approval process in place for any contract executed by the CPE that exceeds a five-year term.[11]

Generally, CESA is supportive of resource procurement that co-optimizes for system and local capacity needs, thereby avoiding duplicative procurement when any given resource could be strategically developed and contracted to meet both needs. In spite of this, CESA has a number of questions regarding whether this proposal is needed to support Summer 2022/2023 emergency reliability. The scope of this proceeding is focused on supply- and demand-side solutions and strategies to support system capacity shortfalls, not particular local capacity needs. It is therefore unclear why PG&E needs to leverage its CPE function rather than its separate and firewalled procurement team to procure the necessary system capacity resources. There is nothing that prevents PG&E from seeking and procuring Local RA attributes from new, incremental preferred and energy storage resources through solicitations conducted by its procurement team. If incremental procurement is directed to address an effective PRM as done in the Phase 1 Decision, the Commission can already direct the IOUs to procure resources on behalf of all customers and allocate costs through the Cost Allocation Mechanism ("CAM"). No justification is provided by PG&E to this end, other than to say that this proposal will support the delivery of reliability benefits during net peak.[12]

Without these clarifications or justifications, CESA has concerns that this proposal could infringe on the procurement autonomy of non-IOU LSEs by having not only System RA but also Local RA resources procured on their behalf. In the spirit of the competitive neutrality protocols directed in D.20-06-002 and adopted in D.20-12-006,[13] CESA also has questions regarding the results of the recently-run solicitations, which should have already procured for local capacity area needs over the next three years, and whether PG&E would be advantaged by having the CPE procure for Local RA

[10] PG&E Opening Testimony Chapter 9 at 7-8.
[11] D.20-06-002 at Ordering Paragraph ("OP") 22.
[12] PG&E Opening Testimony Chapter 9 at 9.
[13] D.20-06-002 at OP 24 and D.20-12-006 at OP 9.

resources through bilateral negotiations without consideration of the relative costs and effectiveness of the portfolio of all shown and bid Local RA resources in an all-source solicitation. These questions and concerns must be addressed.

However, if the Commission moves forward with authorizing CPE procurement, any new resources should be procured under long-term 10-year contracts, consistent with the requirements established in past IRP procurement orders. Whereas there is only a three-year forward requirement for Local RA requirements, new resource procurement requires long-term contracts spanning at least 10 years to support its financial and project development viability.

C. Utility-owned storage should be pursued to support emergency reliability needs, but the IOUs should also broaden the focus to third-party-owned storage solutions that can meet Summer 2022/2023 commercial online dates.

All three IOUs expressly supported pathways for UOS to be authorized through more expedited approval processes in support of Summer 2022/2023 emergency reliability needs. PG&E, on the one hand, recommended the general use of a Tier 2 advice letter process[14] rather than an application as required in the most recent IRP procurement order,[15] while SCE commented on the need to have a timely procurement authorization if a Tier 3 advice letter process is used.[16] By contrast, SDG&E detailed a specific end-to-end proposal and timeline for a Commission procurement order, Tier 2 advice letter submittal and approval, and commercial online date, as well as either clarified eligibility of the CAM or SDG&E's newly proposed Reliability Enhancement Cost Allocation Mechanism ("RECAM").[17] In support of this proposal, SDG&E provided a detailed list of potential

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[14] PG&E Opening Testimony Chapter 9 at 10-11 and 13.
[15] D.21-06-035 at OP 13.
[16] SCE Opening Testimony at 58-59.
[17] SDG&E Opening Testimony (Utility-Owned Resources, Witness Jenell McKay) at 4 and SDG&E Opening Testimony (Comments on Energy Division Staff Concept Paper, Witnesses Jeff DeTuri and Habibou Maiga) at 4-5.

energy storage projects under consideration or development on either SDG&E substation property or that transfer ownership of projects to SDG&E under build-transfer agreements, amounting to around 200 MW of incremental capacity with some that could be online in December 2022 depending on contract approvals.[18]

CESA agrees that these UOS projects identified by SDG&E represent promising potential for new incremental capacity to be added in support of near-term emergency reliability needs and simultaneously aligning with the IRP procurement goals and the state's long-term decarbonization targets. To the degree that these UOS projects are cost-effective and can be delivered ahead of Summer 2022, these projects should be pursued in contract negotiations and development, along the timelines proposed by SDG&E. At the same time, CESA recommends that SDG&E also be directed to consider third-party-owned energy storage solutions that can also meet the targeted commercial online dates, consistent with the guidance established in D.19-11-016,[19] which references D.19-06-032 and Appendix A guidelines governing how an IOU must competitively procure for projects of both ownership types and demonstrate that particular value streams are only obtainable by procuring or investing in utility-owned assets.[20] While the full range of energy storage projects that can achieve commercial online dates by June 2023 is limited, regardless of ownership model, SDG&E will not know whether there may similarly-situated and available energy storage projects in development that could augment battery storage or gas generation sites that have excess interconnection capacity, support retrofits of energy storage to existing standalone solar generation sites, or be in the advanced stages of development for entirely new-build storage sites. With many LSEs in the process of procuring to meet D.19-11-016 and D.21-06-035 procurement orders, there may be third-party-owned energy storage projects that could bid into an SDG&E solicitation for resources that could come online by June 2023 but have not previously bid into SDG&E's solicitation, or there may be projects in

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[18] SDG&E Opening Testimony (Utility-Owned Resources, Witness Jenell McKay) at 9-10.
[19] D.19-11-016 at Conclusion of Law ("COL") 29 and OP 8.
[20] D.19-06-032 at OP 7 and Appendix A at 2-3.

SDG&E's previous solicitations that scored with positive net present value ("NPV") but was not selected in the bid stack. Without conducting a solicitation for third-party-owned projects as well, it will be difficult for SDG&E to make this assessment. A narrow procurement of UOS storage alone also would not adhere to the intent and guidance of D.19-06-032 and D.19-11-016. Along the same lines, Independent Energy Producers Association ("IEP") underscored this point by highlighting how an attributes-based approach would achieve many of the same ends, with UOS projects having no inherent advantage to prefer this ownership model over another.[21]

On the other hand, SDG&E rightly explains how time is of the essence and Commission action to direct the IOUs to initiate solicitations and contract negotiations is imperative to bringing these projects online by Summer 2023. The timelines to issue the procurement authorization by September 15, 2021 and to have final Commission approval of contracts by December 2022 will indeed provide market certainty to developers to invest in additional supply resources for energy storage projects to come online on or before June 2023.[22] Regardless of ownership structure of the project, CESA agrees that a Tier 3 advice letter process likely makes it challenging for projects to secure the notice to proceed with a final, unappealable Commission-approved contract.[23]

In addition to applying the same processes to ensure timely deployment of energy storage projects of any ownership model, CESA thus believes that there may need to be some flexibility from the guidelines established in D.19-11-016 and D.19-06-032 to not necessarily require a side-by-side competition and comparison for UOS versus third-party-owned energy storage projects,[24] which can be challenging, complex, and time consuming in both the bid evaluation and contract review process, countervailing the intended purpose to expedite and streamline procurement and contract review. Given that contracts must be executed before the end of this year to meet Summer 2023 commercial

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[21] IEP Opening Testimony at 7.
[22] SDG&E Opening Testimony (Utility-Owned Resources, Witness Jenell McKay) at 5-7 and 12.
[23] *Ibid* at 12.
[24] D.19-06-032 at 21 and D.19-11-016 at 49-50.

online dates, it is more reasonable to authorize the procurement of both types of projects in parallel and separate solicitations rather than in a single solicitation that requires side-by-side comparisons. So long as SDG&E or other IOUs also solicit third-party-owned project offers given the ownership agnostic nature of the need for incremental capacity for Summer 2023, the Commission should apply the established guidelines in this way in the interim for the purposes of near-term emergency reliability, thus balancing the intent of ensuring competitive outcomes for new resource procurement (given the circumstances) and the need to move quickly to accommodate short lead times.

D. Hybridization of battery storage to sites where there is excess interconnection capacity or where hybridization can free up and improve the emissions profile of the gas portfolio should be prioritized.

In the pursuit of incremental capacity additions within a very short timeframe between now and Summer 2022 or 2023, CESA and many other parties have conveyed that there is a smaller subset of options. Yet, leveraging available interconnection and deliverability capacity at existing sites represents a means to bring new capacity resources online in short order. Such is the case with the potential addition of energy storage at existing gas generation facilities, which Middle River Power ("MRP") and others recommend that the Commission consider and pursue.[25] As explained by MRP, the hybridization of short-duration battery storage with simple-cycle gas peaking capacity can support an improved environmental profile of the existing fossil fleet as they support near-term reliability needs.

These claims are affirmed through past CESA-commissioned modeling that showed that near-term hybridization of approximately 1,110 MW of existing gas peakers (222 MW of storage) in reduced annual 2022 greenhouse gas ("GHG") emissions of the IRP system portfolio by up to 350,000

[25] MRP Opening Testimony at 17 and SDG&E Opening Testimony (Comments on Energy Division Staff Concept Paper, Witnesses Jeff DeTuri and Habibou Maiga) at 13-14.

metric tons ("MT"), as well as NOx emissions in disadvantaged communities ("DACs") by up to 100,000 lbs/year via a 42% reduction in the annual number of gas peaker plant unit starts.[26] As peaker units are committed to provide spinning reserves, other more efficient thermal units on system must be backed down, but by reducing a peaker unit's Pmin to 0 MW, hybridization of peaker units allow more efficient dispatch across the system. Based on these modeled benefits supporting MRP's claims, CESA recommends that the Commission prioritize the hybridization of the existing gas fleet with energy storage resources in their consideration of efficiency improvements that could be made in retaining gas units for near-term reliability. In doing so, the Commission will be establishing a glidepath to transition away from the current gas portfolio.

E. Pre-RA deliveries or proxy RA should be allowed to support near-term reliability where conditions and locations allow.

Like CESA, several parties recommended eligibility of "proxy RA" resources or to leverage energy-only ("EO") energy storage resources in the interim at particular locations to support near-term reliability, until Full Capacity Deliverability Status ("FCDS") can be achieved without major upgrades or until FCDS can be secured with time.[27] In particular, the California Wind Energy Association ("CalWEA") proceeds to detail how the current FCDS study methodology may be overly conservative, not reflecting the proliferation of energy-limited resources that makes it less likely for simultaneous dispatch of resources.[28] Full-on changes to the methodologies and approaches to assign RA credits or unbundling of System and Local RA credits are likely larger topics that requires collaboration with the CAISO as well as consideration of the structural slice-of-day ("SOD") reforms being contemplated in

[26] *Comments of the California Energy Storage Alliance on the Ruling of Assigned Commissioner and Administrative Law Judge Seeking Comment on Policy Issues and Options Related to Reliability* filed in R.16-02-007 on December 20, 2018. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M254/K771/254771224.PDF

[27] LS Power Opening Testimony at 6; SDG&E Opening Testimony (Comments on Energy Division Staff Concept Paper, Witnesses Jeff DeTuri and Habibou Maiga) at 10-11; and CalWEA Opening Testimony at 4.

[28] CalWEA Opening Testimony at 4-5.

R.19-11-019, but CalWEA raises additional considerations in support of some flexibility regarding EO energy storage resources to address near-term system capacity shortfalls as proxy RA resources.

F. Timely resolution of paired storage eligibility in the ReMAT and PURPA SOC can support near-term reliability.

Among other things, Solar Energy Industries Association ("SEIA") recommends that the Commission resolve paired storage issues related to PURPA SOCs in R.18-07-017 and consider 20-year contracts to support incremental capacity from solar-paired-storage resources through this procurement mechanism.[29] CESA wholeheartedly agrees. Comments were submitted by parties on February 10, 2021 in response to an Amended Scoping Memo in R.18-07-017, as well as on June 9, 2021 in response to *Administrative Law Judge's Ruling Seeking Updated Information Regarding the Renewable Market Adjusting Tariff Program* in R.18-07-003 regarding the eligibility of co-located and hybrid storage projects. Understandably, time is often needed to resolve complex policy, legal, or technical issues, but the ReMAT and PURPA SOC represent a potentially time-efficient procurement mechanism (as compared to longer all-source solicitations) to bring on additional capacity resources, especially with the storage component enhancing and firming the capacity value of otherwise standalone solar resources that face declining average effective load carrying capability ("ELCC") values over time. In CESA's view, as expressed in comments in the respective proceedings,[30] the question of eligibility can be readily addressed through assurances that the paired storage can only charge from the ReMAT- or PURPA-eligible generation facility.

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[29] SEIA Opening Testimony at 18-19.

[30] *Comments of the California Energy Storage Alliance on the Administrative Law Judge's Ruling Seeking Updated Information Regarding the Renewable Market Adjusting Tariff Program* filed on June 9, 2021 in R.18-07-003 at 8-9: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M387/K561/387561678.PDF; and *Comments of the Solar Energy Industries Association and the California Energy Storage Alliance on the Amended Scoping Memo and Ruling of Assigned Commissioner Clifford Rechtschaffen* filed on February 10, 2021 in R.18-07-017 at 4-6: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M366/K442/366442141.PDF

V. Emergency Load Reduction Program (ELRP) and Other Demand Response (DR) Modifications

Due to the lack of participation in the ELRP, the Commission staff proposed a number of modifications targeting this particular issue, but many parties echoed CESA's concerns that the program is limited in its design to entice many participants due to the infrequency of events, uncertainty of revenues, and more attractive options, among other things.[31] As evidenced by CESA's new program proposals, there is potential for more value and services to be extracted from stationary and mobile BTM battery and thermal storage resources, beyond the minimal expectations of ELRP resources. CESA leaves it to the Commission to determine whether CESA's proposal in whole or certain elements are adopted as part of a new standalone program, or new customer group or category within an existing program, but it is important to take note of the various common issues and solutions cited by parties in opening testimony.

A. Capacity or reservation payment structures are needed to drive more meaningful and robust participation in the ELRP.

Multiple parties echo calls to establish capacity or reservation payments in order to "add more definition" to the ELRP and support the customer and DRP investments needed to enable their participation, where for relatively initial capital investments required for BTM energy storage, the pay-for-performance incremental load reduction ("ILR") compensation alone will not be sufficient to drive these investments.[32] CESA agrees in particular with contentions by Enel X and CPower ("Joint DR Parties") that a capacity or reservation payment is needed to support the physical sizing and enrollment of storage capacity and enable their participation in the program, even though capital investments typically require long-term contracts to make the projects financially viable.[33] To ensure meaningful participation and support forward planning, as evidenced by IOU and staff proposals to include advanced load nomination requirements and payments against these nominations, the Commission

[31] CALSSA Opening Testimony at 4.
[32] Sunrun Opening Testimony at 16-17; Enel X and CPower Opening Testimony at 23-24.
[33] Enel X and CPower Opening Testimony at 24

should reconsider its position on capacity or reservation payments and adopt one of several options proposed by CESA or other parties.

At minimum, higher payments of $2/kWh or more could be commensurate with customers who agree to lower trigger points or more frequent minimum dispatch. CESA observed a wide range of demand response providers ("DRPs") and DER aggregators commenting on how resources actually want to be able to participate more and provide a higher level of DR service, which should be commensurate with higher payments. The Joint Parties, for example, recommended adding a Flex Alert trigger as well as day-of triggers for Group B customers, which is motivated by the fact that its member companies want to be able to be more frequently dispatched.[34] Like CESA, the California Solar and Storage Association ("CALSSA") also submitted a proposal to establish a much lower trigger point based on CAISO day-ahead market prices,[35] pointing to how BTM storage resources can and want to be more frequently dispatched than what ELRP is currently designed for. For BTM energy storage that has a higher capital expense than other DR technology types, this higher level of payment is particularly necessary to generate enough revenues to offset the initial investment and is in line with its technical capabilities to provide enhanced DR without customer attrition effects. Absent a capacity payment, meaningful ELRP participation under a pay-for-performance structure will only occur if there are more opportunities to perform.

Only PG&E opposed higher incentives, citing the fact there the program has just launched for one season.[36] However, there is already sufficient evidence to increase or modify payment structures based on reported evidence of limited participation by staff, as well as reported limited interest from industry on their intentions to participate now and going forward in the ELRP. While direct enrollment data or customer feedback is more evidentiarily sound, reported information, as attested to the best of their abilities by parties in these testimonies, should be sufficient in this case to justify changes due to

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[34] CEDMC, et al. Opening Testimony at 8 and 11 and Joint DR Parties Opening Testimony at 22-24.
[35] CALSSA Opening Testimony at 5-6.
[36] PG&E Opening Testimony Chapter 2 at 1.

the limited time to enact changes needed to support Summer 2022/2023 reliability, in addition to the steps required for DRPs to recruit, secure, and enroll customers.

B. ELRP features should generally be consistent across customer groups, including around compensation and dual participation rules.

CESA agrees with many parties on the need to ensure consistent program requirements across different customer groups, such as those involving dual participation, minimum participation thresholds, or compensation levels. First, given the fact that any verified kWh in response to ELRP events are the same regardless of customer type, CESA agrees with several parties that the proposed $2/kWh energy payment should be applied to all customers, not just A.1 and A.2 customers.[37] Second, dual participation rules should be similarly applied across customer groups. Sunrun observes that residential customers are prohibited from dual participation in other DR programs without much explanation from staff, which is inconsistent with other customer classes and would deter their participation in the absence of a capacity payment.[38] Finally, minimum size thresholds for eligible participation should be consistent where reasonable, especially if one of the goals is to increase enrollment in the program. With this in mind and in line with the staff concept proposal, for example, SCE proposed to expand ELRP eligibility for A.1 customers by reducing the participation threshold from 200 kW to 100 kW.[39] By extension, the same spirit of encouraging more customer participation in ELRP could be applied in adjusting the participation size threshold for A.4 customers down to 100 kW aggregations, which Sunrun adds would also be consistent with national policy via Order No. 2222 to enable DER aggregations of 100 kW minimum size.[40] In sum, CESA recommends that the adopted ELRP modifications be made to consistently apply to all customer groups where logical and

[37] SCE Opening Testimony at 38 and CEDMC, et al. Opening Testimony at 7.
[38] Sunrun Opening Testimony at 18.
[39] SCE Opening Testimony at 35.
[40] Sunrun Opening Testimony at 17.

reasonable. A kWh reduction is the same regardless of customer type, and the same goal of encouraging more customer participation should motivate changes to different sub-groups.

C. Various IOU and CCA pilots should be approved and funded, with consideration of how they can be incorporated into planning and operations and eventually assessed for scaling potential.

CESA continues to advocate for our Enhanced Storage-Backed Demand Response ("ESB-DR") and Permanent Load Reduction ("PLR") Incentive proposals, which could be established as new standalone programs or incorporated as a category or component within existing DR programs. Additionally, CESA sees merit in other parties' proposals, or some of the elements of the proposals involved and recognizes that the lower hanging fruit may be additional funds or expansions to existing DR pilots and programs in place, such as the various pilots proposed by the IOUs and two community choice aggregators ("CCAs"). In particular, Marin Clean Energy ("MCE") and Peninsula Clean Energy ("PCE") proposed a number of pilot expansions in support of the Phase 2 objective and needs of this proceeding, including:[41]

- MCE's Peak FLEXmarket Program
- MCE's Energy Storage Program
- MCE's MCEv Sync Program
- PCE's Net Peak Residential Storage Load Modification
- PCE's Residential EV Managed Charging
- PCE's V2B Pilot Expansions

In addition, the IOUs similarly proposed several pilot extensions or expansions, including but not limited to the following:[42]

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[41] MCE Opening Testimony Chapter 2 at 1-42 and PCE Opening Testimony at 3-20.
[42] PG&E Opening Testimony Chapter 7 at 2-3 and SCE Opening Testimony at 30-32.

- PG&E's Demand Response Emerging Technology ("DRET") Program
- SCE's Virtual Power Plant ("VPP") Phase II Pilot

CESA is generally supportive of pilots to advance understanding and testing of new models to enable customer load and storage flexibility and thus supports the approval of the above pilot proposals. While supportive of the innovation and market transformation objectives of these pilots, CESA understands the need to balance concerns of the multitude and territory-specific nature of DR programs, approaches, and models creating customer confusion against the ability for non-IOU LSEs, as more nimbler administrators, to create new demand flexibility opportunities.[43] To this point, CESA hopes that the Commission will develop a pathway for innovative DR programs and approaches, including those from non-IOU LSEs, to be scaled and be made available statewide[44] through a long-term source of funding if the approaches are found to be effective. This will be critical to the success of the BTM storage and load flexibility market to have this long-term market certainty and direction.

D. The shared concerns with automatic enrollment point to not adopting staff's proposal to automatically enroll all residential customers in ELRP.

CESA observed that many parties opposed the staff concept proposal for automatic enrollment of all residential customers into the ELRP, leading to various issues such as an increase in free ridership, the complexity and delays associated with disenrollment of customers, the conflicts against various dual participation and customer communication rules in place, and the implementation challenges of making baselines and conducting settlement for a wide range of customers.[45] Especially with the wide range of interesting and potentially high-impact DR pilot proposals in place or in consideration as part of this proceeding, CESA agrees that automatic enrollment of all residential

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[43] *See, e.g.*, MCE Opening Testimony Chapter 1 at 4, Chapter 2 at 17-18, and Chapter 3 at 2-3.
[44] *See, e.g.*, Recurve Opening Testimony at 7-8.
[45] SCE Opening Testimony at 8 and 65-67; SDG&E Opening Testimony (Demand-Side Actions, Witnesses E. Bradford Mantz and Michael McConnell) at 18-19; and MCE Opening Testimony Chapter 2 at 17-18 and Chapter 3 at 2-3

customers would present risks and challenges to enabling participation in higher-impact DR programs and opportunities that enable greater levels of load flexibility and customer engagement. As a voluntary program in its current state, the ELRP should not be the program to which a large portion of customers are directed and enrolled.

E. The EV/VGI Aggregation Pilot should be approved given their market and technical potential, with the minimum dispatch requirement providing financial certainty and advancing VGI learning objectives.

PG&E and SCE opposed staff's proposed EV/VGI Aggregation Pilot by citing how there is limited availability and production capacity of eligible solutions as well as a number of "known barriers" to their deployment, including Rule 21 interconnection regulations, the prohibition from exporting under the Net Energy Metering ("NEM") tariff, or the ineligibility for the Self-Generation Incentive Program ("SGIP").[46] However, none of the cited reasons are compelling or relevant reasons to reject or defer the proposed pilot.

First, the Vehicle-Grid Integration Council ("VGIC") detailed the significant market potential and technical capabilities of the EVs and electric vehicle supply equipment ("EVSEs") deployed today as well as projected through 2023.[47] Contentions to the nascency of vehicle-to-grid ("V2G"), vehicle-to-building ("V2B"), or vehicle-to-home ("V2H") – collectively referred to as V2X – does not sufficiently capture the capabilities available today or in the near future, where barriers to their widespread use and adoption are not due to the underlying technology or resource but rather the development of enabling programs, market models, compensation structures, regulations, and interconnection processes. One of those critical known barriers was addressed through the adoption of interconnection pathways for bidirectional EVSEs via D.20-09-035, leveraging many of the same

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[46] SCE Opening Testimony at 68 and PG&E Opening Testimony Chapter 7 at 4-5.
[47] VGIC Opening Testimony at 6-9.

processes and standards in place for stationary energy storage. Addressing this barrier was a threshold issue to enabling bidirectional capabilities to be utilized for customer and grid purposes, which is now driving market interest, but it is also important to note that the decision's requirements are still pending final resolution,[48] such that SCE citing one pending interconnection application is not contextualized within the fact that this commercial pathway has not yet been fully implemented.

Second, concerns about NEM or SGIP eligibility are irrelevant to assessing whether the pilot should be approved, as they only serve to highlight additional barriers to V2X resources.[49] Even as SCE points to other opportunities currently open to EV resources, there are few opportunities for V2X resources. In contrast to the IOUs' VGI pilot proposals,[50] this pilot has a concerted focus on enabling EV/VGI aggregations and exports specifically for emergency reliability events and will test the use of sub-metering in baseline and performance measurement – some of the key barriers highlighted in the VGI DR Workshop Report.[51]

Importantly, PG&E and SDG&E opposed the 30-hour dispatch requirement because it does not align with the program objective and design of the ELRP and would not have been needed for such a frequency of proxy events in 2019.[52] As a voluntary, pay-for-performance program, however, ELRP would not provide financial certainty regarding expected revenues from EV/VGI customer enrollment in the program. At least with a minimum 30-hour dispatch requirement, a customer can expect a certain minimum level of revenue depending on the amount of kWh that they agree to be available for dispatch in the program. Especially without a capacity/reservation payment or an upfront enrollment incentive as the ELRP is currently constructed, the minimum dispatch requirement is needed. Even if

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[48] SDG&E Advice 3774-E, SCE Advice 4510-E, and PG&E Advice 6209-E.

[49] It is not entirely clear that V2X should even tie its ability to get credits for exports through NEM eligibility, which would require a potential definitional change to mobile batteries as an "addition or enhancement" like with stationary storage and may limit V2X resources from charging exclusively from the onsite NEM-eligible generator under current rules, which would limit customer charging for driving needs.

[50] PG&E Advice 6259-E and SCE Advice 4542-E submitted on July 15, 2021.

[51] *See* VGI DR Workshop Report at 25-27.

[52] PG&E Opening Testimony Chapter 7 at 4-5 and SDG&E Opening Testimony (Demand-Side Actions, Witnesses E. Bradford Mantz and Michael McConnell) at 22-23.

ELRP-related conditions are not triggered to warrant dispatch, this is a pilot where the IOUs could identify and define either lower trigger points (*e.g.*, CAISO Flex Alerts instead of the CAISO AWE signal) or other applications for which these aggregated resources could be useful (*e.g.*, distribution deferral).

Q: Does this conclude your testimony?

A: Yes. I appreciate the opportunity to submit this testimony on behalf of CESA.

Appendix A:

Declaration in Support of Reply Testimony of Jin Noh on Behalf of the California Energy Storage Alliance

DECLARATION IN SUPPORT OF Reply TESTIMONY OF JIN NOH ON BEHALF OF THE CALIFORNIA ENERGY STORAGE ALLIANCE

I, Jin Noh, am the Policy Director for the California Energy Storage Alliance (CESA). Having worked for CESA for over six years, I am currently managing policy and regulatory affairs for CESA and its over 100 member companies. My business address is 2150 Allston Way, Suite 400, Berkeley, CA 94704. I declare under penalty of perjury that the foregoing facts in this document are true and correct to the best of my knowledge.

Executed on September 10, 2021 at Berkeley, California.

Jin Noh