Docket No.: R.20-11-003

Exhibit No.: CESA-001

Date: January 11, 2021

Witness: Jin Noh

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

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 opening testimony is to submit our party proposal on various solutions that could be pursued by the Commission to address Summer 2021 emergency reliability needs and beyond. We focus 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 Commission's consideration of expedited Integrated Resource Plan ("IRP") procurement, expanded electric vehicle ("EV") participation in DR programs, and certain changes to existing DR programs.

I. Introduction

CESA continues to support the intent, purpose, and importance of this proceeding, especially in light of the Joint Agency's *Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm Report* ("PRCA Report"), which highlighted the various causes and contributing factors to the August 14-15, 2020 rotating outages as well as their collective recommendations. To address this urgent need, the Commission should seek to procure emergency reliability capacity from both supply-side and demand-side resources that adhere to the state's long-term decarbonization and policy objectives. In this vein, CESA appreciates the opportunity to submit this testimony, Exhibit No. CESA-001, to present and respond to various proposals for distributed energy resource ("DER") procurement or programs. Rather than limiting the scope of new capacity additions or contracting to supply-side resources, such as through a recent December 28, 2020 immediate procurement authorization, CESA strongly recommends that the Commission consider the proposals and responses submitted in our testimony as well as other parties' testimonies that could serve to advance the role of DERs in meeting this urgent need.

II. Summary of Recommendations

Using the Staff Proposal questions as guidance to this testimony, CESA offers the following key recommendations:

- Establish a new $504-million, 450-MW ELRP program that provides capacity reservation payments for "enhanced" DR resources that are fast-start, frequently dispatched, and reliable.
- Authorize the creation of DR program offerings in all existing and future Transportation Electrification Programs.

- Utilize submeters embedded in the EV supply equipment ("EVSE") to advance EV participation in DR programs and recognize the full load curtailment contributions of EV loads.
- Defer proposals on reforms to Proxy Demand Resources ("PDRs"), such as day-ahead market bid price cap, to the appropriate Commission proceeding or CAISO initiative or after more comprehensive and granular performance data is available.
- Do not adopt the proposal to offer load-serving entities ("LSEs") incentives to accelerate the online date of resources with commercial online date ("COD") of August 1, 2021.
- Issue a procurement order for Summer 2022 by March 2021.
- Allow and encourage pre-RA delivery period contract provisions to support emergency reliability in the short term and RA in the long term.
- Establish upfront procurement parameters and demonstration requirements along with streamlined regulatory submission and review processes.
- Streamline Commission-jurisdictional Rule 21 interconnection timelines and processes.

III. Emergency Load Reduction Program (ELRP)

In the attached Staff Proposal, the Commission proposed for consideration a new ELRP that would seek the participation of demand-side resources in a potentially multi-year program outside of the CAISO market and outside of the RA and CEC planning framework. In other words, they would not be counted for RA or embedded in the CEC load forecast. Additionally, the Staff Proposal is considering compensation for the emergency load reduction and/or energy supply as an after-the-fact "pay-for-performance" payment instead of a standby or capacity-like payment.

CESA strongly supports the development of a new ELRP. As the Commission considers modifications to existing DR programs, the Commission should develop the ELRP as a new grid capacity investment and service program outside of the RA framework that can address key gaps missing in the suite of investor-owned utility ("IOU") DR programs and procurement mechanisms. In particular, the ELRP should be developed to support new resource investment in fast-start, frequently dispatchable DR resources such as storage-backed DR resources or permanent load curtailments that address the emergency reliability needs in the August and September months during the net load peak hours. Such resources are not currently supported or incentivized sufficiently in the current suite of DR options and represent the very type of resources that, if procured and deployed via the ELRP, would mitigate concerns identified by the Department of Market Monitoring ("DMM") in its analysis of DR performance relative to their "count" for RA credits or supply-plan capacity.[1] "Enhanced DR" options are not available in current DR programs that set participation and performance requirements based on a minimum standard (or an upper limit) as opposed to compensating resources that can do more. Although the current DR programs have been structured in this way to support technology neutrality and encourage broader customer participation, this lowest-common-denominator approach has not adequately valued resources that do not face the same limitations as traditional DR resources.

CESA agrees with several aspects of the Staff Proposal on the ELRP. First, the program should be established as a multi-year program[2] to support the deployment of the resources that are capable of providing the fast-start and frequent dispatch services needed. In comments to the Order Instituting Rulemaking ("OIR"), CESA observed that many parties focused on the risks of customer attrition associated with "extracting more" out of existing DR programs, such as through increases in the number of calls beyond the current program parameters. However, resources such as battery and

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[1] *Report on system and market conditions, issues and performance: August and September 2020* ("DMM Report") published by the CAISO Department of Market Monitoring on November 24, 2020 at 33 and 56. For example, DMM explains: "The additional capacity not available in real-time is associated with long-start proxy demand response resources which have no obligation to be available to the ISO's residual unit commitment (RUC) or real-time markets if not scheduled in the integrated forward market. These underlying resources have start-up times of 5 hours or greater. Most of this underlying capacity was offered in the day-ahead market at the $1,000/MWh bid cap while also submitting high startup and minimum load costs, resulting in resources being uneconomic to commit in the day-ahead market."
[2] Staff Proposal at 5.

thermal storage are capable of frequent cycles to provide load response that is separate from the host customer load, thereby reducing and/or eliminating customer attrition effects since the host customer does not directly experience the load response. To deploy these resources, however, a multi-year program is needed to, instead of setting requirements to enable easy customer enrollment and disenrollment, support capital investments in new storage resources with project lifetimes ranging between 10 and 30 years.[3] The Commission, LSEs, and the CAISO will have better assurances as well that capacity is backed by real "steel in the ground" (*e.g.*, in the form of energy storage projects); though installed capacity does not necessarily translate on a one-for-one basis to operational or contract capacity, there is greater assurance of the latter simply based on the fact that it is backed by physical capacity. Likewise, as physical resources are deployed in our proposed ELRP, the capacity "procured" can be committed on a longer-term basis, alleviating concerns about fluctuating participation levels on year by year. At minimum, CESA thus recommends that the ELRP be established as a five-year program.

Second, CESA supports establishing the ELRP as a program that operates outside of the RA framework.[4] There are logical and feasibility reasons for doing so. Significantly, with this proceeding focusing on emergency reliability needs that are above and beyond the current RA requirements established based on a 1-in-2 loss-of-load expectation ("LOLE") standard, there is no immediate policy or planning-based reason to require the ELRP to function within the RA framework. Any identified heat-storm-driven "capacity" needs using 1-in-5 or 1-in-10 conditions are not yet incorporated in the RA planning framework and have to be taken up in the RA proceeding (R.19-11-009). If the Commission eventually decides to revise its planning standard accordingly, the Commission can then

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[3] See, *e.g.*, *Order Establishing Term-Dynamic Load Management and Auto-Dynamic Load Management Program Procurements and Associated Cost-Recovery* issued on September 17, 2020 by the State of New York Public Service Commission in Case 18-E-0130, Case 20-E-0112, and Case 20-E-0113 at 2: "The current DLM program structures pay for yearly performance and result in a bias towards short-term, low-capital investment solutions." https://assets.documentcloud.org/documents/7216843/DLM.pdf

[4] Staff Proposal at 5.

consider whether to incorporate the ELRP within the RA framework – at which point ELRP resources should be attributed RA credits or supply-side RA value. Some proxy of capacity value for Summer 2021 or Summer 2022 could be used to inform compensation levels without it being required to be tagged as "RA" *per se* and being subject to RA must-offer obligations. Furthermore, incrementality issues are simplified since any capacity that delivers during the months and hours pursuant to this program would be than the higher than 1-in-2 planning standard and not captured in the CEC load forecasts for RA purposes.

However, CESA recommends a different compensation structure than proposed in the Staff Proposal, where compensation for the emergency load reduction and/or energy supply is only done after-the-fact on a "pay for performance" basis only. In other words, the Staff Proposal opts against any standby or capacity-like payment.[5] To attract the capital investments necessary to "procure" the enhanced DR needed to support emergency reliability needs, however, after-the-fact payments alone will not support the capital investments needed to provide incremental emergency reliability resources. CESA instead recommends a capacity reservation payment that is paid in part upfront to support deployment and in part on an ongoing basis based on test and actual dispatches, with adjustments to the ongoing payment portion based on actual performance. CESA discusses the compensation aspect of the proposal in our response to the staff guidance question below (see Sections III.A.ii and III.M).

A. Proposed ELRP Structure

To address the gaps and needs discussed above, CESA proposes an ELRP structure that is elaborated in the below sections and in response to the Commission staff's guidance questions. Fundamentally, the proposed ELRP is intended to help bring the incremental new capacity resources online to support emergency reliability needs in the near term through a program

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[5] *Ibid*.

structure that supports the deployment of fast-start and frequently dispatched resources such as BTM energy storage. The program structure can be summarized as follows:

- **Program budget:** $504 million
- **Program period:** 2021-2025 (inclusive)
- **Program capacity target:** 450 MW
- **Program participation:** First-come, first-served, with appropriate vetting and pre-approvals
- **Capacity reservation payment rate:** $1.20/W of enrolled capacity ($0.60/W paid upon interconnection and test dispatch; $0.60/W paid out across a 10-year period through annualized payments), with adders to be considered
- **Pay for performance:** To be determined. Annualized payments of 50% of capacity reservation can be reduced if not meeting performance thresholds
- **Dispatch trigger:** $750/MWh day-ahead market price (non-market-integrated) with day-ahead notifications to deliver enrolled capacity
- **Base performance period and requirements:** 5-9pm, four-hour continuous energy capability
- **Resource eligibility:** Battery energy storage, thermal energy storage, permanent load-shifting ("PLS"), vehicle-to-grid ("V2G") resources, and other DERs that can meet base performance requirement
- **Exports allowed:** Yes, subject to Rule 21 interconnection processes and requirements, and compensated in accordance with enrolled capacity
- **Program administration:** IOU as the administrator as a start but open to non-IOU LSEs as well following the appropriate processes
- **Multiple-use considerations:** Dual enrollment allowed in other DR programs as appropriate and contracting for or participation in other grid services allowed outside of potential dispatch periods

With the ELRP mirroring many elements of the Self-Generation Incentive Program ("SGIP"), some may ask why our proposed ELRP is necessary if SGIP currently has funds available. To this point, CESA responds that SGIP is quickly depleting funds even though the waitlist data points to substantial demand from customers for BTM energy storage systems. Without SGIP funds, BTM energy storage resources have limited means to support new deployments for various purposes (*e.g.*, customer bill management, resiliency) and are ill-fits for the current suite of DR programs. Competitive solicitation opportunities for generation capacity and/or distribution services are available but can be challenging to participate in and represent one-off, "lumpy" opportunities that are not conducive to steady deployments. Importantly, ELRP is seeking to provide an important reliability service, a goal which is significantly different from that of SGIP. As a market transformation program, SGIP projects are not required to deliver reliability services and have much reduced obligations, focusing instead on customer needs through voluntary response to retail rates and following real-time greenhouse gas ("GHG") emissions signals as required by the program. By contrast, while mirroring the SGIP structure in some ways in terms of setting payment rates that drive deployment, the ELRP has more significant obligations, representing payments for services as opposed to a market transformation technology incentive. These distinctions highlight how our proposed ELRP is not duplicative with SGIP.

Because of the compressed timeline to develop and submit testimony and the fact that resource-limited parties like CESA typically do not develop full program proposals, we caveat that the proposed ELRP is not fully developed. Program structure, design, implementation, and evaluation needs to be more fully fleshed out, but we lay forth the foundations of a new ELRP structure that could be modified or revised upon Commission and party feedback.

i. Proposed ELRP Budget

CESA recommends an ELRP budget set at $504 million. We detail how CESA arrived at this budget level below but are open to different approaches, with the important factor being that the program should support relatively more capital-intensive, new-build resources that are able to deliver the fast-starting and frequently dispatchable type of DR service needed as part of the ELRP.

First, CESA relies on the analysis provided by the CAISO in this proceeding on the capacity shortfall in the July through September 2021 period by assuming 1-in-5 weather conditions and thus a 20% planning reserve margin ("PRM"). In its stack analysis, after accounting for available RA capacity, the CAISO identified capacity shortfalls between 450 MW and 3,300 MW across these months when focusing on the net load peak hours[6] – the times during which solar production is low or zero and when the CAISO triggered load shed of 1,000 MW and 500 MW in hour ending 19 on August 14, 2020 and August 15, 2020, respectively.[7]

Accordingly, to balance "piloting" this new program design and structure and serving the low end of the capacity shortfall identified by the CAISO, CESA recommends that the proposed ELRP be established based on the 450-MW number, though the actual MW supported under this ELRP may differ. To establish the five-year program budget, the Commission could, at minimum, assume that capacity value of ELRP-funded resources at the capacity procurement mechanism ("CPM") soft-offer price cap of $6.31/kW-month since CPM resources may be required via backstop procurement to meet the emergency reliability need, with ELRP resources having the incremental benefit of supporting the state's policy goals. Whereas the CPM is intended to contract for and secure existing capacity, ELRP is targeting new incremental build such that

[6] *Comments of the California Independent System Operator on Order Instituting Rulemaking Emergency Reliability* filed on November 30, 2020 in R.20-11-003 at 3-4. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M353/K226/353226841.PDF

[7] *Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm* published by the CAISO, CPUC, and CEC on October 6, 2020 at 41-42. http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf

basing a program budget based on $6.31/kW-month is already low (as discussed further below).

Next, CESA calculated the $/kW-year for ELRP resources by assuming that they would be delivering its capacity-like resources for months June through October, inclusive. The five-month assumption for performance of ELRP resources is justified based on these months generally aligning with the summer months in retail rate schedules that simplify customer understanding. Additionally, these months generally align with RA requirements, specifically the performance months as required for Category DR or Category 1 resources within the maximum cumulative capacity ("MCC") bucket framework (*i.e.*, May through September).[8] If the Commission evaluates whether to reflect heat storm conditions in setting RA planning requirements, ELRP resources will already be well-positioned to count toward these RA needs, either as a supply-side resource or (as CESA would prefer) as RA-reducing credits. Lastly, these five months are consistent with the CAISO analysis with a one-month buffer before and after the July through September analysis period in case heat storm events occur earlier or later than expected. As a result, using the June through October operating period for ELRP resources, CESA arrived at an annual capacity value of $30/kW and, across a five-year program period, $150/kW. With a program funded assuming $150/kW to get 450 MW,[9] a $71-million proposed program budget would support the procurement of capacity services from ELRP resources and allow for the recovery of the variable costs of providing these services.

However, DR programs that merely allow for the provision of capacity services already exist through the Base Interruptible Program ("BIP") or the Capacity Bidding

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[8] *See* D.20-06-031 at 58. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K083/342083913.PDF
[9] $6.31/kW-month * 5 months * 5 years * 450 MW * 1,000 kW / 1 MW = $70,987,500

Program ("CBP"), among others. To actually procure new DR capacity that is fast-starting and frequently dispatchable, payment structures are needed on a long-term basis to support the recovery of the fixed costs of new capital investments as well as the variable costs of delivering the grid service. They must reflect their 10- to 30-year lifetimes, depending on the technology, and thus assume higher new capacity values. Consistent with the assumed cost of new entry used in the 2020 Avoided Cost Calculator, the program budget could be extrapolated by using the $112/kW-year cost of new entry,[10] which on a 10-year basis,[11] amounts to $1,120/kW. To meet the target 450 MW with new resource investments that deliver services across a 10-year period, CESA arrived at a $504-million proposed budget for the program.[12] If the proposed ELRP budget is too substantial, it can be adjusted downward with a lower capacity target.

ii. Proposed ELRP Reservation Payment

CESA preliminarily recommends an ELRP reservation payment set at $1.20/W or $1,200/kW for a base four-hour energy storage system, but we are open to feedback and revisions to this structure. At this time, CESA only specifically proposes an ELRP reservation payment for BTM energy storage resources (including both battery storage and thermal storage resources) but we do not foreclose the development of other or varied reservation payment structures for other forms of DERs, so long as they are able to meet

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[10] *Energy Division Staff Proposal for 2020 Avoided Cost Calculator Update* published on April 16, 2020 in R.14-10-003 at 12. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M334/K786/334786698.pdf

[11] The 10-year basis for projecting the proposed budget is in line with minimum equipment eligibility requirements of SGIP. Since the Commission found this minimum lifetime requirement to be sufficient to deliver ratepayer value as a long-standing asset for SGIP purposes, the similar rationale could be applied here, even though many resources could have longer lifetimes. *See* 2020 SGIP Handbook Section 4.2.1 at: https://www.selfgenca.com/documents/handbook/2020. Furthermore, this is consistent with the contracting requirements for new resources pursuant to D.19-11-016. *See* Conclusion of Law 28 of D.19-11-016: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF

[12] $112/kW-year * 10 years * 450 MW * 1,000 kW / 1 MW = $504,000,000

the base eligibility and performance criteria. Due to our knowledge and expertise with energy storage but less so with other DER technology types, we defer to other stakeholders on how our proposed ELRP could be adapted to accommodate to non-storage DER technologies.

The $1.20/W reservation payment level for a base four-hour energy storage system adapts the SGIP structure, which offers declining step incentive rates for commercial customers at $0.35/Wh (currently in Step 3) and for small residential customers at $0.25/Wh (recently in Step 5 but now has dropped to $0.20/Wh Step 6 levels), with flexibility on the duration of the system and incentive rates that reflect the different Watt-hours of the actual storage project in kind. Rather than proposing carve-outs and differentiated rates per customer sector, we recommend starting with the $0.30/Wh as a "mid-point" that could create opportunities for all types of customers.[13] Instead of setting a per-Watt-hour payment level that varies based on energy duration, CESA proposes to simplify this structure as a capacity reservation payment in $/W or $/kW that aligns with the net load peak period needs and potential future RA requirements, leading us to arrive at $1.20/W or $1,200/kW.[14] As discussed in the above section, this reservation payment amount is roughly consistent with (though slightly higher than) the assumed cost of new entry used in the 2020 Avoided Cost Calculator. Importantly, CESA makes a further distinction from SGIP in that SGIP makes incentive

[13] We note that the SGIP commercial budget has held steady at Step 3 incentive rates for some time, likely due to higher costs of these projects. By contrast, residential projects have experienced substantial uptake. Even though we are basing the ELRP reservation payment at a higher rate than what is currently available in SGIP for small residential customers, this may be appropriate for simplicity, without the need for sector-specific carve-outs. *See* the SGIP Program Metrics page for the latest rates: https://www.selfgenca.com/home/program_metrics/

[14] $0.30/Wh * 4 h = $1.20/W.

payments based on the installed capacity of the project whereas we propose that the ELRP be based on "enrolled" capacity for the reservation payment rate.[15]

This reservation payment level is consistent with uptake levels seen in SGIP, where incentive levels generally around this level have still driven deployments. Whether a market transformation technology incentive as in the case of SGIP or a grid-service payment such as the one for the proposed ELRP, these "revenue streams" only need to cover a portion of the costs, with a combination of private capital, customer bill savings, and other stacked value streams (*e.g.*, other incremental and complementary grid services) being able to cover the rest of the costs, in addition to the less quantified benefit of customer resiliency in some cases. The Step 5 incentive rate for small residential customers was set at $0.25/Wh,[16] which translates to $1/W for the base four-hour energy storage system that would be eligible for the proposed ELRP. On average, for small residential customers investing in an energy storage system with four or greater hours of duration, the SGIP incentive claim was $3,341, representing approximately 15% of the total eligible project costs ($21,858). For commercial customers, all of the program administrators ("PAs") are currently in Step 3, where the incentive rate is set at $0.35/Wh, translating to $1.40/kW for the base four-hour energy storage system that would be eligible for the proposed ELRP. On average for commercial customers investing in an energy storage system with four or greater hours of duration, the SGIP

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[15] For example, a 7-kW energy storage system could enroll at and reserve ELRP payments for 8 kW if they can deliver 7 kW of load reduction along with 1 kW of exports during the dispatch period. As a grid service program supporting new-build resources, installed capacity is less relevant if exports are allowed and the reservation payment can be used to support the enrolled capacity amount. So long as the promised capacity amount is delivered, the installed capacity is less relevant.

[16] This is the most recent SGIP step for small residential customers with robust customer participation data. Step 6 just opened for small residential customers, but reservations and data reflecting those reservations are actively ongoing.

incentive claim was $310,493, representing approximately 24.4% of the total eligible projects costs ($1,271,760).[17]

To drive deployments, the ELRP reservation payment should be apportioned such that part of it comes in the form of upfront payments with the remaining funds coming through ongoing performance-based payments to recoup the full qualifying payment amount. Similar to SGIP, CESA recommends that the reservation payment could be divided 50/50, where half of the full qualifying payment amount ($1,200/kW) is paid to the resource upon completing interconnection, achieving permission to operate ("PTO"), and conducting a test dispatch to demonstrate the capacity of the resource. The other half of the full qualifying payment amount would be paid on an ongoing basis after the fact, in line with the Staff Proposal recommendation to pay for performance. This type of split payment structure has generally worked for commercial storage projects (*i.e.*, under the performance-based incentive ["PBI"] structure) and could be similarly appropriately applied to residential projects that seek ELRP reservation payments for reliability services. Annual capacity-based pay-for-performance amounts can be calculated for each of the ten years the resource is expected to perform, with payments reduced if not achieving the required level of performance. Performance tiers (*e.g.*, 95% and above, 90%) could be established at which payments would be reduced, but because of the high performance expected of resources participating in our proposed ELRP, CESA does not envision the need to have performance tiers at lower levels as done for other DR programs or mechanisms (*e.g.*, reduced payment at 80% of qualifying capacity).

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[17] Note that certain outliers in the SGIP data may be leading to these results. These numbers were calculated based on the SGIP Real-Time Public Report downloaded on January 8, 2021, available here: https://www.selfgenca.com/report/public/

Finally, CESA believes that the reservation payment can be adapted in different ways to meet various objectives. Given the higher cost but significance and prioritization for projects supporting low-income and disadvantaged community customers, CESA supports a reservation payment structure that recognizes the incremental costs and value-add of developing such projects, such as through an equity adder component. Similarly, longer-duration ELRP resources (*e.g.*, 6-8 hours) could be supported with duration-based adders that recognize the need for longer-duration resources in emergency reliability events, particularly during prolonged heat waves such as those experienced in August 2020. At the same time, since these incremental hours of duration may not be "utilized" as frequently based on observed CAISO day-ahead market prices and the trigger price we have set, the incremental reservation payments could perhaps be discounted for the incremental hours beyond the base four-hour requirement. These adders would ultimately reduce the MW capacity that could be supported through the ELRP, but the Commission can decide whether to structure it in a way to pursue different objectives with a lower target, or alternatively, could choose to increase our proposed budget accordingly.

iii. Proposed ELRP Resource Requirements

As a condition of receiving ELRP reservation payments, these resources must participate in ELRP events that are triggered based on a pre-set CAISO market-informed price point in the day-ahead market (see more details in Section III.C), which are intended to target the net load peak period needs where prices have generally peaked. Furthermore, eligible resources must be capable of providing at least four-hour continuous energy in order to support the duration of the net load peak period as well as to position these resources for potential future RA consideration, though resources capable of providing up to six-hour continuous energy are also eligible. Due to the urgency of the Summer 2021 need, the program will be open to enrollments on a rolling first-come, first-served basis with the appropriate yet streamlined vetting processes to

ELRP participants. The specific administration and implementation steps can be developed if the Commission and other stakeholders find merit in this type of idea and wish to pursue it further. Finally, the proposed ELRP can give preference to projects that can come online by August 2021, and in descending order, priority to projects that can come online in the earlier part of the 2021-2025 program period.

B. Policy and Legal Justifications for Proposed ELRP

CESA believes that the Commission has sufficient policy and legal justifications for implementing a new ELRP to support the deployment of enhanced DR resources that can deliver emergency reliability capacity. The Commission has broad ratemaking authority to approve rates to fund programs such as the ELRP,[18] which do not have to be legislatively enacted, as well as broad authority and discretion to regulate public utilities.[19] Moreover, in the December 21, 2020 Scoping Memo in R.20-11-003, the Commission established the scope to include "other opportunities to increase supply for summer 2021" and "other opportunities to reduce peak demand and net peak demand hours in summer 2021." So long as the ELRP is structured in this way, CESA's proposed ELRP proposal falls within the scope of the proceeding. As explained in the OIR, the Commission should seek "to identify and execute all actions within its statutory authority" that address the key objective of this proceeding – *i.e.*, to ensure reliable electric service in the event that an extreme heat storm occurs in the summer of 2021.[20] CESA believes that the proposed ELRP can achieve these key objectives and looks forward to reviewing parties' comments on key areas of improvement.

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[18] *See* Cal. Pub. Util. Code § 454

[19] Pursuant to Cal. Pub. Util. Code § 701, "[t]he commission may supervise and regulate every public utility in the State and may do all things . . . which are necessary and convenient in the exercise of such power and jurisdiction."

[20] OIR at 2 and 12.

C. **<u>Program Trigger</u>: CAISO suggests "the dispatch trigger [for ELRP] could be a Warning or Stage 1 emergency or its equivalent." What is the case for or against limiting the trigger to CAISO-declared Warning/Emergency stage vs. extending the trigger discretion to Alerts or day-ahead?**

The ELRP should use a CAISO market-informed trigger that sets dispatch based on market conditions, as reflected in prices that indicate emergency reliability needs and resource scarcity. Even as the ELRP operates outside of the RA framework and thus outside of the CAISO market, the ELRP administrator should use day-ahead market prices to inform dispatch while providing advanced day-ahead notice to ensure that ELRP resources are prepared to respond (*e.g.*, having sufficient state of charge in the case of storage). Similar to the IOU DR programs, existing processes could be used where the CAISO alerts the IOU schedulers to activate their DR programs and the IOU or LSE can then bid load/demand in ways that reflect the expected performance of the ELRP resources.

In assessing at what price to set the dispatch trigger, CESA contemplated two different approaches that could be pursued for the ELRP. On the one hand, since the ELRP operates outside of the RA framework and because emergency reliability capacity needs are not yet reflected through revised RA planning standards (*e.g.*, 1-in-5, 1-in-10), a case could be made to not have ELRP resources triggered before reliability DR resources that count for RA capacity. In this way, ELRP resources would be displacing or be utilized before resources that actually count toward RA requirements. On the other hand, one of the value propositions of our proposed ELRP is that it could support enhanced DR resources that could be utilized as fast-start, frequently-dispatched DR resources unlike many other traditional DR resources and programs that may have limits to their participation and face risks of customer attrition if called upon too frequently. By setting ELRP behind reliability demand response resources ("RDRRs"), which have a minimum bid price of $950/MWh, the very advantages of our proposed ELRP resources would not be leveraged.

As such, CESA believes a more appropriate price trigger could be informed by assessing the day-ahead market prices during the days where load was shed (*e.g.*, August 14 and 15) and/or projected to reach historic levels (*e.g.*, August 17-19, September 5-6) in line with the emergency reliability needs tied to heat storm events, particularly in the net load peak hours.[21] These load conditions are illustrated in the graphs from the DMM Report below:[22]

Figure 3.1 Actual peak load in the ISO compared to day-ahead forecast peaks (August 13 – 21)

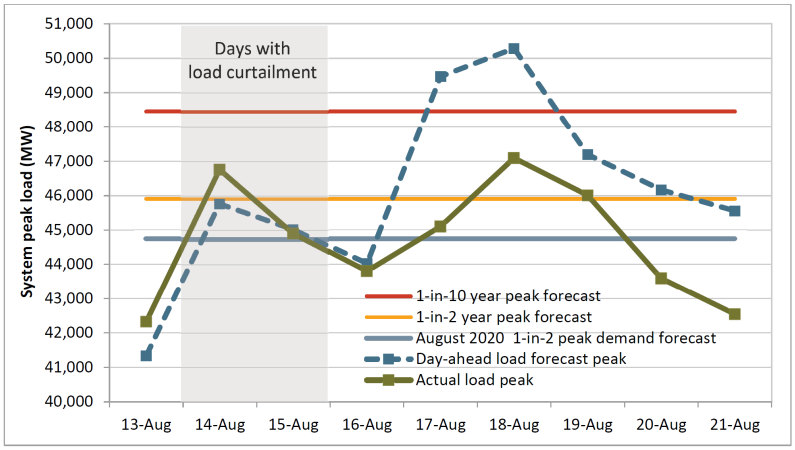
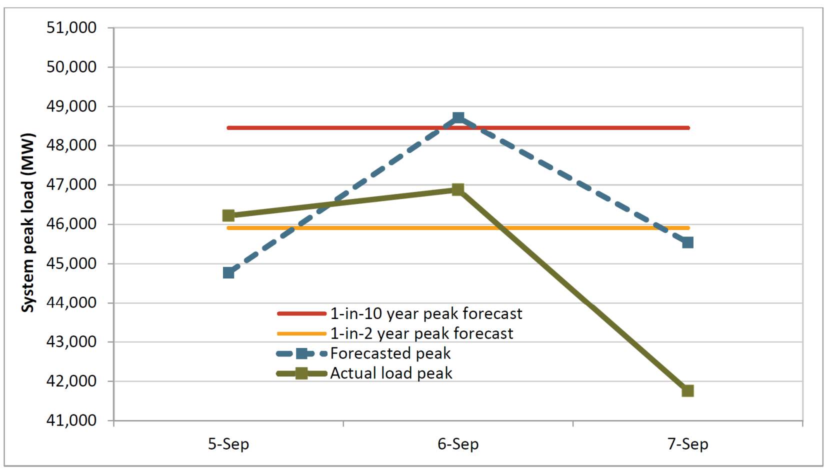


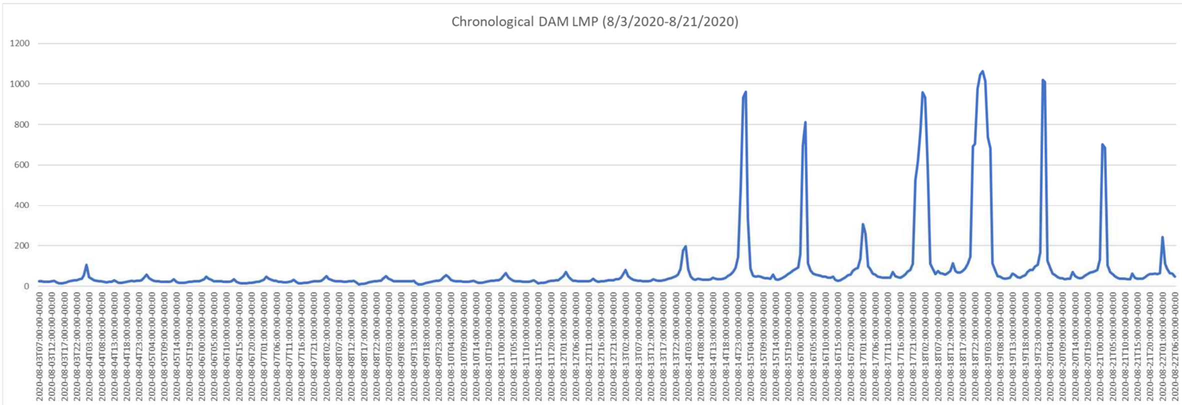
Figure 3.2 Actual ISO peak load compared to day-ahead load forecast peaks (September 5 – 7)



In CESA's analysis of CAISO day-ahead market price data, we observe major price spikes, particularly in hour ending 19 and 20 on those high load days, generally exceeding

[21] DMM Report at 7-9 and 11. Note that DMM reported how the "difference between the forecasted load peaks and the actual load peaks on August 17 to 19 appears to be due in large part to both the conservation efforts of Californians and out of market production."
[22] DMM Report at 12-13.

$800/MWh in most territories but still falling below the $950/MWh minimum bid for RDRRs. See, for example, the day-ahead market price trends from August 3 through August 21.[23]



To make some more use of ELRP resources beyond the most extreme of days, CESA proposes looking at the percentile of day-ahead prices across these days to identify the appropriate level to set a trigger dispatch. Whereas the development of programs for traditional DR resources would use this information to identify the number of calls that would fit within the program parameters and limitations, the ELRP has greater flexibility and capability to support more frequent needs. However, those capabilities should be balanced with the fact that ELRP represents resources that are outside of the RA framework and have the potential to be utilized ahead of what should be used as day-to-day RA capacity, including both Proxy Demand Resources ("PDRs") and RDRRs. As a result of the enhanced capabilities of our ELRP resources, there is no science to what the trigger point should be, but we preliminarily propose setting it at $750/MWh roughly based on observed day-ahead market prices at the 97th percentile on those extreme weather and load days.[24]

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[23] The data has been obtained through the OASIS Portal (http://oasis.caiso.com/mrioasis/logon.do) and assessed the Locational Marginal Prices ("LMP") for the Day-Ahead Market (DAM) of all hours of August 3, 2020 through August 21, 2020, as well as August 24, 2020 through September 2020.
[24] *Ibid*.

Percentile (0-1)	For the hours of August 13-16	For the hours of September 6-9
0.50	48.12	51.06
0.75	78.82	74.88
0.90	166.53	122.36
0.95	372.99	215.83
0.96	522.23	298.97
0.97	711.90	363.14
0.98	824.23	391.39
0.99	936.30	437.75
1.0	962.51	868.68

CESA is open to discussing with the Commission, CAISO, and other stakeholders on what the appropriate trigger point should be and looks forward to feedback.

D. <u>Program Trigger</u>: Should the IOUs be allowed to trigger ELRP for localized transmission and distribution emergencies? Why or why not?

Yes, CESA supports the potential for ELRP resources to be triggered for localized transmission and distribution emergencies. As a separate and incremental service, the usage of ELRP resources for these other purposes needs to be reflected in the program's compensation level. Though there may be some cases where heat storm events are correlated with transmission and distribution emergencies, our understanding is that such correlation may not hold true in all instances, such as with public safety power shut-off ("PSPS") events, infrastructure maintenance outages, etc. With this in mind, CESA believes that it is simpler and cleaner to enable ELRP resources to be eligible to participation in separate programs, tariffs, or solicitations to provide these transmission and distribution services. The proposed Partnership Program in R.14-10-003, for example, is considering tariffs to support project-specific distribution deferral, while various pilots are being developed in R.19-09-009 to provide grid resiliency. The Commission should allow for these various programs and tariffs to overlay.

E. <u>Eligibility – Load Reduction Resources</u>: Should customers who are already enrolled in IOU (directly or via aggregators) or third-party demand response programs or critical peak pricing be permitted to participate in the ELRP? If so, what specific program rules

will be needed to ensure that dual participants are not compensated twice for the same load reductions? If there are distinctions in the rules depending on the DR program or rate, please describe. Please provide an estimate of potential MWs available for each dual participation permutation.

Yes, CESA supports the eligibility for dual enrollment of customers in ELRP as well as for other DR programs. For IOU-run DR programs, there should be visibility into accounting for the same load reduction, especially if one is a market-integrated program versus a non-market-integrated one, such as ELRP. Barriers to dual enrollment with third-party DR programs can also be managed through data sharing provisions to use third-party DR participation data to conduct performance evaluation and settlement. Some of these challenges can also be overcome in cases where the single customer is dual participating through resources with separate settlement meters, where a submetered storage or EV load participates in one program and the whole customer load participates in another.

F. <u>Eligibility – Load Reduction Resources</u>: What rules and processes need to be in place to ensure that the load reductions expected from dual participants are appropriately accounted for and communicated to CAISO for grid operations?

CESA wishes to explore this issue but believes that this could be managed through information sharing and depends on the nature of the dual-enrolled program. With our proposed ELRP as a day-ahead and market-informed (but not market-integrated) resource administered by the IOU, for example, load scheduling may be coordinated and made visible to the CAISO when the other program is dispatched on a day-of basis.

G. <u>Eligibility – Load Reduction Resources</u>: Should customers be permitted to use prohibited resources during an ELRP event to achieve incremental load reduction in excess of any load reduction commitments under other dual enrolled DR programs?

CESA has no comment at this time.

H. <u>Eligibility – Load Reduction Resources</u>: Should customer-sited behind-the-meter combined heat and power (or other technology, please specify) energy supply resources without firm capacity contracts be permitted to participate in ELRP, provided they have existing export permits and are able to provide metered firm export energy in response to an emergency request? Given that these resources may require longer lead times to become available, should there be separate trigger (e.g., restricted maintenance call) and availability window defined for these resources? If so, how should they differ? Please provide an estimate of potential MWs available.

CESA has no comment at this time.

I. <u>Eligibility – Energy Supply Resources</u>: Should exports from customer-sited behind-the-meter hybrid (i.e., solar plus storage) resources during an emergency dispatch be eligible for compensation under ELRP? Please explain how potential interconnection, safety, and reliability concerns would be addressed. Please provide an estimate of potential MWs available. If these resources have already been accounted for as load reduction in the demand forecast, how could marginal energy in response to an emergency be metered and confirmed as a marginal additional energy supply resource.

Yes, exports from customer-sited BTM hybrid solar-plus-storage and standalone storage should be eligible for compensation under the ELRP. In terms of potential double compensation for exports, this is a non-issue since exports are not modeled in the CEC forecast and because the provision of reliability services in accordance with the ELRP are outside the RA framework. With the ELRP reservation payments based on enrolled or "procured" capacity as opposed to nameplate installed capacity, load reduction plus exports can be measured for performance evaluation at the meter. However, while these exports should be eligible for compensation, CESA does not believe that the ELRP or determinations made herein related to the ELRP would displace the need for a long-term RA framework to recognize the capacity value for exports – an issue that is currently being considered in Track 4 of the RA proceeding (R.19-11-009).

Safety and reliability concerns associated with exports can be addressed in the interconnection process. For new standalone energy storage resources, they can submit an interconnection application and be reviewed to provide exports rather than being studied for non-export operations – the predominant configuration of such projects due to the lack of compensation for exports. Hybrid solar-plus-storage resources generally should not face this issue since they are already allowed to and studied for exports. Additionally, CESA encourages the Commission to explore how even non-exporting energy storage systems could be studied for exports on an exceptional basis or as needed pursuant to their intended ELRP operations, leveraging the Power Control Systems ("PCS") capabilities that have been standardized through UL PCS Certification Requirements Decision ("CRD"), developed to use PCS instead of separate relays to support non-export or limited-export operations. These capabilities have been adopted by the Commission to ensure cost-effective energy storage pairing with Net Energy Metering ("NEM") generation (*e.g.*, solar-only charging mode) and has led to the Commission's adoption of more modernized Rule 21 tariffs that recognize, for example, limited export operations within set parameters.[25] The Commission similarly directed the consideration of technical approaches (*e.g.*, switching between different PCS modes) to "better provide backup power during PSPS events while preserving NEM program goals by limiting the ability to charge from the grid to only during pre-PSPS periods" as one of the near-term strategies to support customer resiliency in the

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[25] *See* D.20-09-035 at 164-165: "We find that Issues A and B can also be addressed through the adoption of a modified Proposal A-B 3, which allows an inverter approved for non-export and limited export to be set using different maximum export value settings at different times of the year, when meeting the qualifications for either Proposal A-B 1 or A-B 2."
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M347/K953/347953769.PDF

Microgrids proceeding (R.19-09-009).[26] Similar technical proposals could be considered for the purposes of the ELRP.

J. <u>Eligibility – Energy Supply Resources</u>: Are there other customer-side resources with the capability to supply energy during an emergency that should be eligible for participation under ELRP? Please discuss any associated special requirements or issues and provide an estimate of potential MWs available.

Yes, CESA supports the expanded eligibility of the ELRP to include thermal energy storage ("TES") and PLS resources, as well as EVs and EV supply equipment ("EVSE").

i. PLS/TES Potential as an Emergency Reliability Resource in ELRP

PLS resources can help meet the goal of the ELRP but the program was sunset in December 2017. Yet, CESA implores the Commission to consider their significant role in providing emergency reliability during the net load peak hours. While most of the ELRP resources discussed above encompass fast, dispatchable resources, the same ends can be met with resources that are able to provide permanent load curtailment with shifted operations. To ensure the permanent shifting of load, ELRP can include a persistent monitoring and compensation scheme.[27]

PLS differs from traditional DR in that it is a form of BTM load modification that is paired with a non-battery alternative ("NBA") form of energy storage that is able to reliably reduce peak demand without incurring a burden on the participating facility.

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[26] *See* D.20-06-017 at 39-40. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K748/340748922.PDF

[27] For reference, details of the since-discontinued PLS program are explained in the following program manual and included a $850/kW incentive: https://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/demandresponse/pls/pls_tes_program_manual.pdf

Large thermal energy storage ("LTES") for cooling or heating loads is one example, but so are other forms of PLS that are akin to dynamic functional energy storage resources and have outsized capacity contributions during heat storm events, such as increased capacity water tanks on hills for potable water systems and flow diversion facilities at wastewater treatment plants. There may be some issues that need to be resolved to bring a large amount of net peak load reduction online this year via PLS, such as attribution, accounting, and reliability of compensation, but many of them are in the process of getting resolved.[28] Consequently, an opportunity exists for this proceeding to clear away the remaining hurdles, thus opening the gates to the entry into the market of a class of assets that could deliver a significant benefit to system emergency reliability in 2021 and the years to come.

Water and wastewater processing are both very good candidates for rapidly deployed and long-lived PLS installations. The water and wastewater sector consume roughly 18% of all electric energy in California.[29] Building cooling and refrigeration loads are also good candidates for PLS, representing over 30% of building energy load and a greater fraction of peak power.[30] Typical PLS installations start in the low hundreds of kW and are often greater than 1 MW, meaning that even a modest number of projects can start to deliver significant impacts. Because PLS is inherently load modifying, there are no interconnection issues of any kind, significantly speeding time to commercial operations. With mature and rapidly deployable technology in place, regulatory implementation solutions in hand, and a considerable amount of overall grid power

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[28] *See, e.g.*, Resolution E-5106 issued on November 12, 2020 and Advice Letter E-5705, *et al*. recently submitted for Commission approval on January 4, 2021. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M350/K762/350762070.PDF
[29] *California's Water-Energy Relationship: Final Staff Report CEC-700-2005-011-SF* published by the California Energy Commission in November 2005 at 1.
[30] *See* California Commercial End-Use Survey: https://www.energy.ca.gov/data-reports/surveys/california-commercial-end-use-survey

associated with this approach, the potential grid impact is significant with less policy development needed, such that PLS warrants attention in the ELRP proceeding. Although these solutions may impose new requirements such as data visibility and reporting, the fact that those requirements have already proven acceptable to industry in other venues should provide greater confidence that they will be workable here.

The first issue surrounds the difference between the traditional 1-in-10 baseline for capacity assets and the NAESB Type I (*i.e.*, the DR baseline) accounting methodology. Cost reductions in sensor technologies have increased the economic viability of continuously monitoring PLS assets. More importantly, many PLS assets, including but not limited to LTES, give their greatest kW contribution to overall system capacity at extreme 1 -in-10 heat storm conditions. Unlike static assets, such as lighting, many PLS assets are "dynamic" in that their curtailable load is variable, and often tied to variables such as ambient air temperature. Research by the University of California showed that the NAESB showed that this approach "under-predicts its impact on the electric grid by as much as 77%, between 38% and 57% on average"[31] Recognizing this situation, after three years of deliberation in R.12-11-005, the Commission issued Resolution E-5106 on November 12, 2020 that directed that the impact of LTES be evaluated for peak kW at 1-in-10 conditions but imposed a continuous monitoring and reporting requirement as a condition.[32] CESA proposes that the same methodology be adopted in this proceeding to allow PLS assets to enter the ELRP. In sum, LTES and many dynamic functional energy storage resources have outsized capacity contributions

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[31] *Valuation of Thermal Energy Storage for Utility Grid Operators* case study prepared by the Western Cooling Efficiency Center at the University of California, Davis. https://wcec.ucdavis.edu/wp-content/uploads/2017/11/Thermal-Energy-Storage-Case-Study.pdf

[32] For further background, refer to *Protest of the California Energy Storage Alliance to Advice Letter 5640, et al. of the Joint SGIP Program Administrators* submitted on June 22, 2020. https://static1.squarespace.com/static/5b96538250a54f9cd7751faa/t/5ef11139775ad552cdaf6f52/1592856890415/2020-06-22+CESA%27s+Protest+to+Joint+PA+Advice+Letter+on+LTES+Methodology+-+FINAL.pdf

during heat storm events and have the added advantage of potentially addressing evolving grid needs as macro-load shapes change over time, including current and/or growing overgeneration issues. These are the very types of resources that should be pursued in this proceeding and through programs such as the ELRP.

The second barrier to PLS assets also involves DR rules. Under a traditional DR arrangement, a system is only occasionally curtailed, and non-curtailment days are used to set the baseline. By contrast, because of the ability of a storage-enabled PLS system to reliably reduce demand, it would be beneficial to use every day of a month in order to receive the benefits of both reduced time-of-use ("TOU") energy charges and reduced demand charges. But to establish or maintain a baseline, the PLS would need to be suspended from operations on occasion during periods where it would normally be in operation. Thus, while turning the PLS asset on and off is useful for baseline purposes and necessary in order to participate in the CAISO market as PDRs, it imposes an artificial and avoidable cost on ratepayers, thereby reducing the number of PLS projects that move forward.

Instead, under a baseline validation dispatch ("BVD") approach, the IOU would schedule specific times with a PLS asset owner to suspend system operation in order to show what load would be there in the absence of such a BVD event, which would allow an LSE to compare the actually observed load before, during, and after the event with the expected values from the file. The innovation would be to not count any additional demand associated with this BVD towards monthly demand charge billing. This could be accomplished by excluding the time BVD time period from calculations of monthly demand, a reimbursement to the customer of the difference through a special tariff, or another mechanism that meets the same need but is easiest for the LSE to implement.

The final issue for PLS involves compensation uncertainty. The energy storage elements of PLS systems are major capital investments, typically costing at least $1 million. While recent developments in SGIP have created improved opportunities for

PLS assets and have driven market interest, the program's budget is limited and decreasing, leading to uncertainty of fund availability despite these resources finally having key performance calculation methodologies adopted. This presents a real barrier to project developers, particularly since the engineering investment involved in analyzing PLS type projects can be substantial. To address this issue, PLS capacity should be eligible in the ELRP, which encourage developers to move forward with development of PLS projects, secure in the knowledge that even if SGIP funds are exhausted, an ELRP fall-back could support their project development efforts.

Storage-backed PLS has many benefits, and many issues can be readily addressed, as described below:

- **Directly measurable:** PLS assets being incentivized under the ELRP could be required to install a submeter for affected load in order to allow even better visibility. Continuous unit-level monitoring and reporting can also be required for the ELRP.
- **Flexible scheduling:** Combined with IOU control of the BVD mechanism described above, the IOU would have the ability to schedule individual BVD events during periods when there is unlikely to be a significant grid need. They could also stagger the events across an individual day, further reducing the impact of PLS assets turning on and off.
- **Performance forecasting and reliability:** Though different vendors use different methods, PLS technology providers have invested significant time and resources into calculate the actual performance of their systems on a day-ahead basis, supporting IOU and CAISO needs.
- **Condition- and equipment-specific settlement:** In the dynamic methodology directed in Resolution E-5106 and proposed in Advice Letter E-5705, *et al*. in R.12-11-005, all of the elements are in place

for a reliable and auditable data-driven settlement process. At any given ambient temperature and building occupancy state, there is a model for the anticipated kW of the base system with the TES system on or off.

By providing multiple benefits, PLS and TES should absolutely be considered as part of our proposed ELRP. They can be deployed quickly and represent extremely long-lived assets. The investment of time by the Commission and other parties to this proceeding in working through the above issues will be fully justified not only by the peak load reduction delivered in the near term, but also in how the clearance of these issues helps advance the market for other demand-side resources in the future.

ii. EV/EVSE Potential as an Emergency Reliability Resource in ELRP

According to the IOU's 2019 EV load research report, it is anticipated that there will approximately 870,000 EVs adopted by IOU customers in 2021.[33] This is anticipated to grow substantially in the coming years. As such, if some portion of the 2021 EV fleet acted as a DR resource, the contributions to the system load could be significant. Assuming a 7-kW charging load per vehicle, and a modest 5% participation rate, CESA estimates that this would equate to over 300 MW of potential DR resource. Additionally, it is worth noting that some of the vehicles currently owned by IOU customers already have bi-directional charging capability and could theoretically inject energy onto the grid during an emergency event. This would effectively double their contribution towards net load peak period needs to provide emergency reliability and, potentially in the future, RA as well. For emergency events in 2021 or 2022, existing EVs are fully capable of responding to either actively reduce load, or export energy onto the grid. More detail on

[33] *Joint IOU Electric Vehicle Load Research Report: 7th Report* filed on April 2, 2019 in R.13-11-007 at 3. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442461674

expanding EV/EVSE participation in existing DR programs are explained in Section IV below.

K. <u>Program Administration and Implementation</u>: Should the IOUs establish a voluntary tariff program that could be open for new customer enrollment in advance of summer 2021? Would the program be open on a pilot basis, and if so, for what time period for enrollment and/or operation?

Yes, CESA recommends that the IOUs establish and administer the new proposed ELRP program since the IOUs, with Commission oversight and authorization, could quickly start up the program. The IOUs should be authorized to seek the appropriate level and mechanisms for cost recovery in developing and administering the program, as well as to support program evaluation and, if needed, marketing and outreach to recruit new customers.

CESA favors a full program that is subject to continuous evaluation for refinement, making improvements as they are identified. Such a full program launch would attract market interest since the Commission would be signaling regulatory certainty and importance of this need. However, given the compressed nature of this proceeding and the novelty of this type of program, including the consideration of new types of resources and the allowance of exports in a DR-like program, CESA understands if the Commission wishes to first establish the ELRP as a pilot. At the same time, the Commission should avoid a perpetual cycle of pilots as done with the Demand Response Auction Mechanism ("DRAM") and chart a pathway to achieve scale upon timely and efficient evaluation and upon meeting certain program milestones and outcomes.

L. <u>Program Administration and Implementation</u>: Should non-IOUs LSEs establish similar programs, and if so, in what time frame?

CESA generally supports preserving the non-IOU LSEs' ability to start, implement, and administer similar programs. Similar to IOU DR programs, if non-IOU LSEs are able to establish processes and protocols to inform the CAISO of the availability of load-modifying resources under their versions of the ELRP that can act like an RA credit, the CAISO will have visibility into the dynamic load resources that are available and can be dispatched in response to load conditions the next day, even though they may not have must-offer obligations and CAISO market participation requirements like supply-side DR resources.

In the interest of time, we advocate for moving forward with IOU-developed and IOU-administered ELRP while charting a pathway for optionality for non-IOU LSEs to develop and administer their own ELRP programs. To this end, CESA understands that the pathway must be outlined for non-IOU LSEs that seek to establish their own ELRP, which may hinge on the cost recovery model used to fund the newly proposed ELRP. CESA does not have a strong view on the appropriate means to recover costs to fund the launch and administration of this program, but because DR funding is typically recovered through distribution rates, the costs associated with administering DR programs are charged to all customers and could serve as a starting point to initiate the ELRP. As such, since both bundled and unbundled customers are paying for the ELRP under a model where the ELRP is funded through distribution rates, all customers, regardless of the LSE from which they take service, should be able to participate equally and be compensated accordingly. For non-IOU LSEs that seek to establish their own version of the ELRP, the Commission has already outlined steps via D.17-10-017 to implement the Competitive Neutrality Cost Causation Principle and to allow community choice aggregators ("CCAs") and direct-access energy service providers ("ESPs") to create and administer DR programs on a level playing field with the IOUs, leading to cost recovery of the IOU ELRP to cease or be credited back for CCA/ESP customers being serviced by the "similar program" as appropriate.[34]

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[34] *Decision Adopting Steps for Implementing the Competitive Neutrality Cost Causation Principle, Requiring an Auction in 2018 for the Demand Response Auction Mechanism, and Establishing a Working Group for the Creation of New Models of Demand Response* issued on November 1, 2017 in R.13-09-011 at 15-31. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M198/K319/198319901.PDF

Alternatively, the Commission could consider approaches that allocate capacity or budgets in advance of ELRP launch to give CCA and ESP customers the option to elect to launch their own ELRP program from the start, similar to the process established in Resolution E-4999 for Disadvantaged Community Green Tariff ("DAC-GT") and Community Solar Green Tariff ("CS-GT") Programs. Under this model, the Commission reserved capacity for CCAs under both programs in proportion to the share of residential customers in disadvantaged communities ("DACs") served by each CCA, with IOU cost recovery only for their remaining capacity share of their programs.[35] CESA defers to the non-IOU LSEs on the preferred approach, though the determination of possible approaches should consider the best approach that would get an ELRP launched in a timely fashion to support emergency reliability needs as soon as the Summers of 2021 and 2022. Either way, non-IOU LSEs should be afforded the option to launch their own ELRP, with processes in place such that they do not have to double pay for duplicative program costs.

M. <u>Compensation</u>: What should be the specified "pay for performance" compensation rate(s) ($/MWh) for load reduction or energy supply achieved by participants during an ELRP dispatch? For example, should there be a price floor, and if so, what amount should participants be paid above that floor? Or should there be a pre-set, fixed compensation rate? Please explain the basis for your proposed compensation rate(s) and any conditions that should be tied to those rate(s). If a resource type is already eligible for compensation under another tariff or contract structure, explain how the resource compensation scheme would prevent double payment?

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[35] *Resolution E-4999. Pursuant to Decision 18-06-027, Approving with Modification, Tariffs to Implement the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs* issued on June 3, 2019 at 13-18. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M297/K211/297211380.PDF

CESA advocates for a pre-set fixed compensation rate that is paid upfront upon meeting certain milestones and eligibility criteria, with the potential to adjust ongoing capacity-based performance payments based on actual performance. To enable customer investment decision-making on the costs and benefits of participation, particularly for capital-intensive projects like energy storage, CESA believes that this type of compensation structure is needed. A purely pay-for-performance compensation for grid services is already in place via DRAM and existing IOU DR programs such as the BIP or the CBP. Upfront, fixed compensation rates, by contrast, are needed to enable customer investment decision-making on costs and benefits of participation. In the future, as a long-term program, if RA is credited or valued for ELRP resources, CESA believes that the compensation structure may need to evolve.

N. Other: What market or regulatory issues related to sector-specific customers or technology configurations (e.g., ports, military, microgrids) should be addressed to maximize potential load reduction under ELRP? Please provide specific proposals along with estimates of potential MWs available in these cases.

CESA supports the exploration of the participation of multi-premise microgrids in the ELRP, which could respond to IOU signals to operate in parallel to the grid and "shed" segments of load that must be served by the broader grid. Typically, microgrids are utilized to manage distribution reliability and resiliency needs due to outages related to transmission and distribution infrastructure or increasingly in California due to PSPS events. However, microgrid islanding compensated within the ELRP should be considered. Since it is unclear how a multi-premise microgrid would fit within a DR construct that measures load reductions against a "typical load" baseline for a single customer premise, permanent load curtailment approaches similar to that for PLS could be developed for microgrid configurations. Rather than seeking voluntary and uncompensated load reductions during Stage 3 emergencies, a compensated load shed could be incorporated in the ELRP for microgrid customers who have the generation and storage resources within a microgrid configuration to serve their own customer loads, thus leading to a more reasonable outcome to achieve the load shed needed for those who are able to do so.

IV. Expanding Electric Vehicle Participation in DR Programs

CESA appreciates and welcomes the Commission's consideration of the utilization of EV participation in DR programs to address the emergency reliability needs identified in R.20-11-003. Many of the key barriers to facilitating EV participation in DR programs are known and have persisted for some time. Though the speed and scale at which these barriers can be overcome may not be achievable by the Summer 2021 timeframe, the Commission should channel the urgency of the emergency reliability needs identified in this proceeding to accelerate key actions in R.18-12-006 and other related venues to quickly facilitate greater EV participation in DR programs. With some of these key issues addressed, CESA believes that EVs can offer low-cost, immediate functional storage and load-shifting capabilities in the near term.

A. <u>Revisions to EV Programs and Incentives:</u> Should the CPUC revise EV programs and/or incentives designed to manage and/or dispatch EV loads in order to respond to a reliability event in Summer 2021?

Yes, the Commission should leverage the embedded capacity and inherent flexibility of EVs by revising existing and recently approved EV programs, as well as in-development frameworks for future EV programs and incentives, to dispatch EV loads in response to a reliability event. The approximately 870,000 EVs anticipated in IOU service territory in 2021 represent a sizable opportunity to respond to a reliability event in Summer 2021 and beyond.[36] To

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[36] *Compliance Filing of Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company Pursuant to Ordering Paragraph 2 of D.16-06-011* (April 2, 2019) in R.13-11-007 at 3.

enable the utilization of EVs and EVSEs for load modifications in response to emergency reliability needs, CESA has two key recommendations.

i. Authorize the creation of DR program offerings in all existing and future Transportation Electrification Programs

Existing ratepayer-funded transportation electrification ("TE") programs that do not incorporate DR programs should do so. Southern California Edison's ("SCE") Charge Ready 2 program recently approved by D.20-08-045 requires all L1 or L2 EVSE site hosts installed under Charge Ready 2 to participate in the Charge Ready DR Program.[37] On December 2, 2020, SCE filed Advice Letter 4363-E requesting to extend the existing Charge Ready DR Pilot Program in lieu of full-scale DR program implementation.[38] SCE's extended DR Pilot program will respond to summer reliability events through "mirroring" its CPP rate, which is currently unavailable to separately-metered EV customers.[39] While this exact model may not be replicable for all existing TE programs like San Diego Gas and Electric Company's ("SDG&E") Power Your Drive ("PYD") Program, Pacific Gas and Electric's ("PG&E") EV Charge Network ("EVCN") Program, and PG&E's EV Fleet Program, CESA believes that EVSE site hosts participating in these programs offer a logical starting point to respond to a reliability event in Summer 2021 by maximizing the value of TE investments, leveraging battery capacity embedded in the cost of already purchased EVs, and building on existing customer outreach and education success.

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[37] *Decision Authorizing Southern California Edison Company's Charge Ready 2 Infrastructure and Market Education Programs* at 94 and OP 18 at 148. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M346/K230/346230115.PDF
[38] *Advise 4363-E. Southern California Edison Company's Charge Ready Demand Response Program Implementation Plan Pursuant to Decision 20-08-045* submitted on December 2, 2020.
[39] *Ibid.*

As such, CESA recommends the Commission authorize each IOU to retroactively incorporate DR programs into already-implemented TE programs (*e.g.*, for the PG&E and SDG&E programs mentioned above) by mirroring their other DR offerings that are currently unavailable to EV customers. For TE investments and program funds moving forward, a dedicated DR or vehicle-grid integration ("VGI") track should be established in R.18-12-006 to bring the needed focus on these matters. This may be outside the scope of the current proceeding, but it could be one of the key procedural recommendations or directions provided to ensure that EVs and EVSEs funded through Commission authorized and approved programs going forward are better positioned in the future to address emergency reliability needs, which is unlikely to be an isolated issue for Summer 2021/2022 but one that could persist for years to come.

ii. Utilize submeters embedded in the EVSE to advance EV participation in DR programs and recognize the full load curtailment contributions of EV loads

EV participation in existing DR programs is limited by the inability to recognize the contribution of load curtailment from EVSE load separate from the host facility load. By directly metering EVSE performance, more accurate baseline calculations are possible for the load curtailment provided by the EVSE load directly. Especially for large EV fleets where there is limited or no onsite host customer load but significant EV load, there is tremendous load curtailment opportunity that would go unrecognized by baselining methodologies using the facility load. Like stationary energy storage resources, EVSEs are physically separate from the host facility and perform differently from the host facility's load curtailment resources (*e.g.*, EVSEs are not temperature sensitive). Recognizing this, the FERC recently approved the CAISO's proposal and tariff changes to apply submetered measurement and performance settlement using the Metered Generator Output ("MGO") methodology, developed within Phase 3 of the Energy Storage and Distributed Energy Resources ("ESDER") Initiative. In the approving Order, FERC explained that " as CAISO points out, EVSE might have very different load profiles from their onsite host load, and therefore might have very different responses to CAISO dispatch." As a result, "[FERC] therefore agree[s] with CAISO that the proposed revisions will better capture EVSE's distinct characteristics, provide more accurate price signals to EVSE owners, and create incentives for them to participate in demand response programs."[40] To fully incorporate submetering strategies beyond just for CAISO energy market participation, the Commission should also enable their use across existing DR programs and for the purposes of delivering emergency reliability and RA capacity services, such as through our proposed ELRP.

A threshold issue to unlocking EV capacity to respond in any future reliability events is the lack of a commercially-viable pathway for submetering technologies. This remains a barrier to stacking VGI value streams and promoting EV participation in DR programs. Critically, the IOUs' recently-filed PEV Submetering Protocol requires customer-owned EVSE submeters meet a 1% field accuracy standard, which is above and beyond the 1% lab and 2% field accuracy standard delineated in NIST Handbook 44 Section 3.40, thus holding EVs to a higher standard than other responsive loads such as smart thermostats. This final protocol also does not consider the difference in lifetimes between revenue-grade utility AMI and commoditized EVSE product offerings. Furthermore, the PEV Submetering Protocol, as filed, does not support submetering for commercial and industrial customers or multi-unit dwellings, which represents a sizable percentage of the EV market.

In sum, submetering should be unlocked in earnest to enable DR and other VGI value streams for a broad set of customers, beyond the proposed residential customers.

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[40] *Order Accepting Tariff Revisions* issued on September 30, 2020 in Docket No. 20-2443-000 at 8. http://www.caiso.com/Documents/Sep30-2020-LetterOrderAccepting-EnergyStorageandDistributedEnergyResourceStakeholderESDERPhase3-ER20-2443.pdf

Several existing EV TOU rates require EVSE be on a separate meter, which strips the incentive for EVs to respond to grid conditions through any programs or incentives other than EV TOU rates. For example, existing DR programs or the proposed ELRP could both fall short of adequately leveraging the capabilities of EVs, as separately-metered EV loads are not able to reduce the baseline of other on-site loads. Therefore, the submetering protocols issue should be resolved as quickly as possible.

V. Changes to Existing Demand Response Programs

CESA does not have any comments or recommendations at this time on potential proposed changes and guidance questions posed in the Staff Proposal regarding the BIP or the CBP, which could serve as means to deliver incremental emergency reliability in Summer 2021 and beyond. We look forward to reviewing and responding to other parties' proposals. Rather, in this section of the testimony, we respond to the Staff Proposal questions on several miscellaneous issues.

A. <u>Proxy Demand Resources (PDR) in CAISO Markets</u>: For PDR resources that are procured for Resource Adequacy (IOU, DRAM and third-party non-DRAM PDR resources) and are able to dispatch only in response to CAISO Day-Ahead Market awards, should the CPUC adopt a bid price cap for these resources bidding in the CAISO Day-Ahead market for the purpose of increasing the probability of these resources being utilized and dispatched during periods of grid stress experienced in Real-Time Market? If so, what should that bid price cap be set at and why?

CESA opposes a day-ahead bid price cap proposal at this time. First, it is unclear whether the Commission or others have demonstrated that PDRs are actually not bidding their marginal costs, and if not, whether the Commission's potential proposal for a bid price cap is the appropriate means to ensure that they do. Default energy bids, for example, were recently established in Phase 4 of the

ESDER Initiative for energy storage resources to provide market power mitigation.[41] During discussions regarding refinements to the Demand Response Auction Mechanism ("DRAM"), the Commission and stakeholders contemplated reasonable reporting requirements for third-party demand response providers ("DRPs") to substantiate the marginal cost bidding of their portfolio resources. These examples, however, highlight how these broader potential issues of PDR scheduling and dispatch in the day-ahead and real-time markets fall outside of the scope of this proceeding. CESA believes that resolution of issues such as those raised in this guidance question is more appropriately addressed in the RA proceeding (R.19-11-009), the Demand Response proceeding (A.17-01-012, *et al.*), or the appropriate CAISO initiatives.

B. <u>Proxy Demand Resources (PDR) in CAISO Markets</u>: What are the potential positive and negative consequences of the Day-Ahead market bid price cap?

As explained above, CESA does not support the adoption of a bid price cap at this time since the issue needs to be further investigated. Premature or rushed adoption of this proposal could have negative unintended consequences that lead to uneconomic dispatch, reduced customer interest, etc.

C. <u>Demand Response Performance Improvements</u>: Based on preliminary settlement data received by the CPUC, demand response resources (IOU and third-party operated) did not always deliver up to their commitments during the 2020 heat waves. This information will be made public in the Final Root Cause Analysis on the August 14 and 15 rotating outages that is anticipated to issue before end of 2020. Please provide: (a.) Reasons for the results; and (b.) Solutions that address the reasons you provide.

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[41] Note that the CAISO adopted an exemption for energy storage resources that are 5 MW or below due to their determination that such resources are unlikely to exercise market power. *See* "Energy Storage and Distributed Energy Resources – Storage Default Energy Bid Final Proposal" published by the CAISO on October 22, 2020 at 12. http://www.caiso.com/InitiativeDocuments/FinalProposal-EnergyStorage-DistributedEnergyResourcesPhase4-DefaultEnergyBid.pdf

As of January 8, 2021, CESA has not had a chance to review the expected "Final Root Cause Analysis" Report and can only base our response to this question based on the "Preliminary Root Cause Analysis" Report as well as the recent November 24, 2020 DMM Report. The DMM Report, for example, explained that 64% of utility DR resources and 58% of DR shown on RA supply plans (*e.g.*, DRAM, non-DRAM third-party DR) was bid into the real-time market in hours ending 19 and 20 on August 14, 2020, relative to their RA capacity counts. In the same hours on August 15, 2020, the performance was 58% and 41% respectively.[42] Based on this initial analysis, DMM recommended that steps be taken to ensure a higher portion of DR used to meet RA requirements is available and utilized during critical net load hours.[43]

While such preliminary performance data should be taken seriously and potential actions and changes should be identified, CESA does not believe that there is enough or sufficiently granular information on the reasons for the results at this time to identify and pursue the solutions to address those shortcomings. DMM's analysis of performance relative to RA capacity values of different resource classes were helpful and identified issues to consider in the RA proceeding to update or modify RA counting methodologies, but the aggregation of DR resources as a resource class and the assessment of their performance in this way may overlook key details that should inform how any changes should be considered. For example, the DR resource class data should be disaggregated to understand how IOU DR program differences may be impacting performance, such as limitations on weekend and holiday performance, maximum call events, and minimum run time requirements. Furthermore, additional analysis is needed on the makeup of individual DR resources, where insight into this information may be limited at this time, though they could be gleaned through analysis by proxy based on the baseline method that resources are registered under.[44] To this end, in the DRAM

[42] DMM Report at 28.
[43] *Ibid* at 71.
[44] For example, PDRs backed by BTM energy storage resources are likely to register under the MGO baseline. With the recent implementation of PDR Load Shift Resource ("PDR-LSR") in Fall 2020 that is only eligible for

Evaluation Report, storage customers were identified as being the DRAM segment that had the highest scheduling rate.[45]

In summary, CESA cautions against purported solutions that are intended to address solutions for aggregate DR performance without identifying key differences in parameters and underlying technological capabilities that drove performance on a more granular level. In this way, the Commission will be able to more accurately identify how different IOU DR programs, DRAM, or other mechanisms could be modified to improve their performance, or as discussed above, find merit in establishing new programs such as the ELRP.

VI. Expedited IRP Procurement

CESA generally supports the Commission's consideration of streamlined and/or expedited IRP procurement programs and processes. Especially in cases where there are short lead times from procurement authorization/directive to COD, all of the steps in between must be streamlined and expedited where feasible, including: the solicitation process (*e.g.*, Request for Offers ["RFO"]) or other sourcing mechanism (*e.g.*, customer programs, tariffs); customer acquisition or site control; interconnection and permitting; regulatory review and approval by the Commission; equipment procurement; infrastructure upgrade and/or project construction; and commissioning and testing. For a majority of these steps and with less than five months until June 1, 2021, the Commission has little or no ability to expedite the online date of resources procured in various 2021-2023 RFOs pursuant to D.19-11-016. Projects will already need to be permitted and equipment must already be procured, with construction already well underway. With projects moving to completion by August 1, 2021 on

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energy storage technologies at this point, the resource ID for the PDR as load consumption and the separate resource ID for PDR as load curtailment can be tied to a single DRRS registration ID to pinpoint and differentiate storage-backed PDR performance from those that are not backed by storage.

[45] *Energy Division's Evaluation of Demand Response Auction Mechanism Final Report* published on January 4, 2019 at 58-59.

already tight timelines, CESA does not support the Commission's proposal to offer an incentive to LSEs accelerate the online date of projects.

Instead, CESA recommends that the Commission consider expedited IRP procurement proposals on a forward-looking basis, where such ideas could have material impacts on mitigating emergency reliability needs beyond Summer 2021. Rather than an LSE incentive mechanism, the Commission should focus on policies and processes within its control and jurisdiction that would achieve the same intended effects:

i. Issue a procurement order for Summer 2022 by March 2021

Due to the minimum lead times required for bringing on any incremental capacity, whether through efficiency upgrades to existing generation, through contracting with uncontracted generation or storage, or through repowering, retrofits, or augmentation with energy storage, the Commission should not narrowly focus on Summer 2021 needs but take timely least-regrets action to ensure Summer 2022 needs are also mitigated through advanced procurement orders. A recent Proposed Decision issued in R.20-11-003 justified the basis for the procurement order for Summer 2021 needs as being consistent with the least-regrets approach of D.19-11-016 and in accordance with the expected imminence of 2021 system reliability needs.[46] Specific comments on the Proposed Decision will be filed and served at a later time, but CESA urges the Commission to view the Summer 2022 needs as imminent as well and then to apply the same level of urgency to direct timely actions to address those needs. If procurement targeting Summer 2022 reliability needs are not included in the

[46] *Proposed Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Seek Contracts for Additional Power Capacity for Summer 2021 Reliability* issued on January 8, 2021 in R.20-11-003 at 9-10. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M359/K001/359001535.PDF

aforementioned Proposed Decision, then CESA strongly recommends that procurement associated with Summer 2022 needs be included, authorized, and directed in the March 2021 Proposed Decision, as planned in the Scoping Memo for R.20-11-003.

ii. Allow and encourage pre-RA delivery period contract provisions to support emergency reliability in the short term and RA in the long term

Due to the long process of existing or new resources to obtain full capacity deliverability status, CESA proposes that the Commission allow and encourage the IOUs to contract for resources that can be operational by Summer 2021 or Summer 2022 but may not obtain a net qualifying capacity ("NQC") in time for these periods. However, as energy-only resources in the interim that operate in the CAISO market consistent with RA must-offer obligations, such resources can still provide incremental reliability benefits more immediately, to the degree that there are such resources online now or in the near future. While there is some risk that the generation or storage cannot deliver its capacity at all times since transmission upgrade needs have not been fully studied, such pre-RA delivery period operations from resources in the deliverability study process can support incremental reliability needs in the near term and provide RA benefits in the long term once full capacity deliverability is secured. Since the emergency reliability needs are not needed for RA compliance purposes, this workaround could be a means to expedite emergency capacity procurement.

Importantly, Southern California Edison Company ("SCE") previously advocated for such workaround proposals when lead times were short, such as in the case of IRP procurement pursuant to D.19-11-016.[47] In fact, SCE included such contract provisions in their Aliso Canyon Energy Storage ("ACES") 1 RFO[48] due to the six-month lead time to COD, which was approved by the Commission[49] without any issue related to these contract provisions despite a real emergency reliability issue tied to the moratorium at the Aliso Canyon natural gas storage facility. The parallels between the Aliso Canyon situation and this current emergency reliability situation points to how similar contracting approaches are precedented and could be used to support expeditious procurement of incremental energy storage capacity.

iii. Establish upfront procurement parameters and demonstration requirements along with streamlined regulatory submission and review processes

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[47] *Comments of Southern California Edison Company (U 338-E) on Revised Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023* filed on October 31, 2019 in R.16-02-007. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M319/K001/319001136.PDF
See at 12: "SCE created a contract to allow for reliability benefits to be provided without actually providing RA. In this agreement, for the time period prior to receiving an NQC/EFC, the project is required to submit bids into the CAISO market consistent with RA must offer obligations. Capacity payments are then prorated based on whether or not the facility followed these requirements. In this respect, the obligations are similar to the RA program, in that the facility needs only to make itself available to the market, and specific dispatching was handled by market mechanisms. Although all projects counted towards the procurement requirement should ultimately be required to provide system RA, the Commission should allow this type of approach as an interim mechanism until projects can qualify for RA counting given the aggressiveness of an August 1, 2021 online date."

[48] *See* SCE Advice Letters 3454-E at 9-10 and 3455-E at 9. *See also*, for specific description of the product, SCE Advice Letter 3456-E at 6-7: "The Product that SCE will purchase and receive during the Pre-RA Delivery Period (the period from achievement of the Initial Delivery Date until the RA Delivery Date) is Seller's obligation to submit economic bids for energy and/or ancillary services at the Project's full capacity every trading day into the CAISO day-ahead and real-time markets consistent with the requirements of a Resource Adequacy Resource. Essentially, the Pre-RA Delivery Period Product is the available capacity that a Resource Adequacy Resource would provide, but without the RA compliance instrument. To the extent the Seller does not bid into the markets in this manner on any trading day, it receives no contract payments from SCE for the trading day. The Product SCE will purchase during the Pre-RA Delivery Period is consistent with the Resolution because it provides additional available capacity to the CAISO Grid to help alleviate electric reliability concerns associated with the partial shutdown of Aliso Canyon."

[49] *Resolution E-4804. Southern California Edison Company (SCE) requests approval of three resource adequacy only contracts with Western Grid Development, LLC, AltaGas Pomona Energy Storage Inc., and Grand Johanna LLC* issued on September 15, 2016. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K245/167245981.PDF

For IOU contracts that require Commission approval, the regulatory submission and review process can present challenges with bringing incremental capacity online in an expeditious fashion if not coordinated and streamlined in appropriate ways. In setting the regulatory review process and standard, the Commission has historically balanced the urgency of the reliability need with the appropriate level of due process, such as in D.19-11-016 where the Commission determined that "Tier 3 advice letters represent an appropriate vehicle to balance a need for expedited approval and appropriate due process for parties wishing to weigh in on an LSE's procurement approval requests."[50] CESA does not have strong views on whether a Tier 2 or 3 advice letter is appropriate, but the timeline for the procurement order, solicitation process, and regulatory review period should be mapped and planned to ensure at least 12-14 months between final Commission approval and the target COD, as a rule of thumb, which may inform the decision on the appropriate regulatory review and approval process.

For example, final Commission approval via disposition letter under a Tier 2 advice letter process or via a Final Resolution under a Tier 3 advice letter process would need to be achieved between July 1, 2021 and September 1, 2021 to meet a September 1, 2022 online date for emergency reliability. This is necessary to account for various project development timelines that need to be accommodated, as discussed in more detail in our Petition for Modification in R.16-02-007.[51] At the same time, CESA understands that the Commission must be reasonably positioned to review contract submissions with the appropriate level of review, such that the Commission may want to establish advice letter submission deadlines for contracts submitted for approval and not be in a position

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[50] *See* Finding of Fact 28 of D.19-11-016, *Decision Requiring Electric System Reliability Procurement for 2021-2023* issued on November 13, 2019 in R.16-02-007. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF

[51] *California Energy Storage Alliance's Petition for Modification of Decision 19-11-016* filed on April 1, 2020 in R.16-02-007 at 7-8. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M331/K080/331080307.PDF

to rush this process due to late submissions.[52] Furthermore, with clear upfront yet flexible procurement parameters, the review process will be aided to ensure that the IOUs understand what must be demonstrated to warrant contract approval and what issues are likely out of scope.

iv. Streamline Commission-jurisdictional Rule 21 interconnection timelines and processes

With the CAISO and IOUs managing and overseeing transmission interconnection and the Wholesale Distribution Access Tariff ("WDAT"), respectively, the Commission should focus on supporting expedited procurement for resources interconnecting under the Commission-jurisdictional Rule 21 tariff. Behind-the-meter ("BTM") resources such as customer-sited energy storage and solar-plus-storage are currently being procured for[53] and can provide incremental capacity as either supply-side DR in RA supply plans or as load-modifying capacity outside of the RA framework, as proposed for the ELRP above. Given the technical nature of the matter, the Rule 21 proceeding (R.17-07-007) is the best venue to address any streamlined interconnection proposals, such that R.20-11-003 and R.17-07-007 should be closely coordinated.

Coincidentally, the Commission is actively contemplating notification-based approaches in lieu of an interconnection application for non-exporting energy storage

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[52] In the process leading to Final Resolutions E-5100 and E-5101, for example, the Commission took approximately four months to go from advice letter submission (May 2020) to Final Resolution (September 2020). If a Tier 3 advice letter process is similarly instituted with four-month review period, the Commission should establish an advice letter submission deadline of May 2021 to ensure due process and afford the needed time to bring resources online by September 1, 2021. These timelines may vary depending on the review level, timing of the procurement order, and other factors (*e.g.*, policy, precedent).

[53] *See* recent 27-MW procurement for BTM energy storage RA capacity in Phase 2 of PG&E's 2020 System Reliability RFO (Advice Letter E-6033) and 5-MW procurement for BTM energy storage paired with solar in the Standard Track of SCE's 2019 System Reliability RFO (Advice Letter E-4373).

systems that have a negligible impact on the distribution system[54] that should be strongly considered for adoption to support expedited IRP procurement from BTM resources. While the notification-only approach applies to small non-exporting energy storage systems and is intended to broadly advance streamlining and perhaps support the urgent need for distribution resiliency, such proposals can also facilitate expedited interconnection and procurement of resources needed for summer emergency reliability, whether through IRP procurement or through a potential, future ELRP.

The consideration of some of the above proposals may not be in scope for solutions to support Summer 2021 reliability, but they could still play an important role in ensuring the timely deployment of supply- and demand-side resources coming online in Summer 2022. Even though the Staff Proposal and questions posed therein focus on expedited IRP procurement solutions for Summer 2021, Scoping Issue 1.a has clearly set addressing Summer 2022 reliability as an issue within scope of this proceeding.[55] As such, in the planned Proposed Decision in March 2021, the Commission should incorporate and adopt the above proposals to support Summer 2022 needs.

B. Should the CPUC offer an incentive to LSEs that voluntarily expedite their 2021 IRP procurement to come online by Summer 2021 (i.e., approximately 6-8 weeks sooner than the August 1st requirement)? For LSEs that support this proposal, please specify the project, resource type, and amount of MW that could be expedited.

No, such an incentive mechanism would do little or nothing to accelerate the online date of projects coming online by August 1, 2021 pursuant to D.19-11-016. The vast majority of the projects

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[54] *E-Mail Ruling Directing Responses to Questions on Working Group Four Report and Issues 11 and 13* issued on November 16, 2020 in R.17-07-007 at 7-8. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M351/K622/351622817.PDF
[55] *Assigned Commissioner's Scoping Memo and Ruling* issued on December 21, 2020 in R.20-11-003 at 2. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M355/K770/355770988.PDF

that have been procured for System RA is for new and incremental standalone or retrofitted storage or incremental renewables plus storage, which already have executed contracts that would need to be amended and are likely in the midst of construction, where efforts to accelerate these construction timelines are likely infeasible and challenging or risky during these COVID-19 times.

C. How should this process be implemented?

As explained above, CESA does not support an LSE incentive mechanism for expedited IRP procurement.

D. How should the incentive amount be determined, and how should the costs of the incentive be allocated?

As explained above, CESA does not support an LSE incentive mechanism for expedited IRP procurement.

E. Should this proposal be limited to procurement for Summer 2021, or should it also include Summer 2022 and 2023?

As explained above, CESA does not support an LSE incentive mechanism for expedited IRP procurement. However, rather than an LSE incentive mechanism, CESA recommends an expedited Tier 3 advice letter mechanism for new resource procurement for Summer 2022 and 2023, consistent with procurement authorized and directed pursuant to D.19-11-016. CESA supports consideration of emergency capacity procurement for not only Summer 2021 but also for Summers 2022 and 2023 given the likely persistence of extreme weather events and the lead time required to meet 2022 and 2023 commercial online dates.

Q: Does this conclude your testimony?

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