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CESA's Comments on DEBA & DSGS Workshop

Additional submitted attachment is included below.

February 17, 2023

Email to: docket@energy.ca.gov
Docket Number: 22-RENEW-01
Subject: Lead Commissioner Workshop on the Demand Side Grid Support Program and Distributed Electricity Backup Assets Program

Re: Comments of the California Energy Storage Alliance on Demand Side Grid Support Program and Distributed Electricity Backup Assets Program Workshop

Dear Sir or Madam:

The California Energy Storage Alliance ("CESA") appreciates the opportunity to comment on the Lead Commissioner Workshop on the Demand Side Grid Support Program and Distributed Electricity Backup Assets Program ("Workshop") held on January 27, 2023. CESA acknowledges the efforts of the California Energy Commission ("CEC") to mitigate the risks California's electric grid faces today and consider the different tools available for deployment over the coming years.

CESA is a 501(c)(6) organization representing over 100 member companies across the energy storage industry. CESA member companies span the energy storage ecosystem, involving many technology types, sectors, configurations, and services offered. As the definitive voice of energy storage in California, CESA is involved in a variety of venues looking at the deployment of distributed energy storage, both in-front-of-the-meter ("IFOM") and behind-the-meter ("BTM"). These venues include near-term emergency reliability proceedings, demand response ("DR") programs, and long-term planning proceedings and initiatives looking to deploy distributed storage to support a more reliable, cleaner, and more efficient electric grid. Given that distributed storage is one of the key resource types that will be deployed in both the Demand Side Grid Support ("DSGS") and Distributed Electricity Backup Assets ("DEBA") programs, CESA's background and experience in providing technical and policy insights are of particular relevance to this matter.

I. INTRODUCTION AND SUMMARY.

Generally, CESA believes that the DSGS and DEBA programs will help provide critical capacity that is needed in the near term. Currently, there are barriers that have prevented projects from being developed, including increasing costs of equipment due to inflation, the delay in deliverability allocations and construction of upgrades for Resource Adequacy ("RA"), lack of capacity payments for BTM energy storage resources inclusive of and recognizing exports, and various barriers to CAISO market participation.

During the workshop, the CEC discussed revisions that are being considered for DSGS for 2023 and beyond, given that the program was launched towards the end of Summer 2022. While rollout of DSGS was limited, valuable feedback was provided during the Workshop from participants. The workshop also covered the CEC's initial proposal for DEBA, including a Summer Challenge Grant that will be launched this year. Generally, CESA commends the CEC for thoughtfully putting together these proposals for both programs and thanks staff for considering stakeholder inputs within the program design.

CESA also agrees with Vice Chair Siva Gunda's comments during the workshop that both of these programs present a chance to have a "regulatory sandbox" to test new innovative ideas for unlocking the value of distributed energy resources ("DERs") and consider how these resources can contribute to California's electric system in the long term. Two elements of both DEBA and DSGS make them appropriate venues for exploring new program and operational models, especially compared to programs overseen by the California Public Utilities Commission ("CPUC"):

1. **The use of taxpayer funds instead of ratepayer funds**: Both DEBA and DSGS receive funding from California's General Fund, instead of California ratepayers. California's progressive taxation system ensures that low-income households are not burdened with excess costs from taxpayer programs, creating opportunities for further exploration. On the other hand, ratepayer funds are collected from all ratepayers regardless of income, with very few exceptions. Given the general growth of electric rates in the state, ratepayer-funded programs must be heavily scrutinized to ensure that any program is worth the additional costs that will be placed on all electric customers.

2. **Statewide reach of CEC programs**: Given that these programs are funded by taxpayers and overseen by the CEC, both DEBA and DSGS will be able to reach publicly-owned utilities ("POUs") that are not under the CPUC's jurisdiction. There are many customers in these territories and having them included in programs when testing new program models and operational patterns is important. Additionally, while the CPUC has some jurisdiction over the Community Choice Aggregators ("CCA"), to the extent that CCA generation customers are investor-owned utility ("IOU") distribution customers, programs that CCA customers are eligible for (*e.g.*, ELRP) are often administered through the IOUs. The ability of the CEC to work directly with CCAs to engage them in both DEBA and DSGS will be immensely valuable.

CESA believes that many elements that are tested in DEBA and DSGS can lead to the creation of long-term programs and frameworks to contribute to California's climate, reliability, and affordability goals. The ability to leverage demand-side customer investments will help reduce the need for investments in bulk generation and transmission and distribution ("T&D") infrastructure, reducing electric system costs. These BTM systems, alongside multi-customer microgrids that combine BTM and IFOM technologies, will help provide customer resiliency, reduce the need for investments in T&D wildfire hardening, and prevent electric equipment fires. Lastly, generation resources have been and are needed in load pockets, and IFOM DERs are well positioned to replace existing fossil fuel power plants that are often sited in disadvantaged communities ("DACs"), which will help to reduce local air pollution in those areas.

Given this opportunity CESA believes that as many customers as possible should be eligible for both DEBA and DSGS, and that customers should generally be able to choose the programs that work best for them. Additionally, we have the following recommendations for the design and implementation of DSGS:

- Third-party aggregators should be eligible to be DSGS program providers.
- DSGS Option 3 should have an out-of-market participation pathway, with some market-informed day-ahead price trigger.
- Sub-metering should be allowed to measure DSGS event response for device-backed resources.
- Visibility concerns should be substantiated by the California Independent System Operator ("CAISO") and load-serving entities ("LSEs").

We also have the following recommendations for DEBA:

- CESA supports the DEBA Summer 2023 Challenge Grant, but BTM participation pathways must be clarified.
- Grant Funding Opportunity ("GFO") evaluation criteria should be further developed around a transparent and streamlined points system to apply weights.
- An incentive-based model is still needed for BTM resources.
- DEBA resources should not be precluded from providing Resource Adequacy ("RA").
- DEBA resources should be allowed to support emergency reliability needs without necessarily providing supply-side RA, such as microgrid resiliency services and load-modifying RA reductions.
- Additional clarity should be provided surrounding the development and implementation timelines for DEBA.

II. GENERAL ELIGIBILITY COMMENTS.

1. Customers should be able to choose the DER programs that work best for them.

In our initial comments on DEBA, CESA recommended three principles for evaluating program design: (1) simplicity; (2) universal accessibility; and (3) new clean energy development.[1]

[1] *Comments of the California Energy Storage Alliance on Lead Commissioner Workshop on Clean Energy Alternatives for Reliability* submitted on November 10, 2022 in CEC Docket No. 21-ESR-01.

CESA believes that the second principle (universal accessibility) is an important principle for both programs. Both DEBA and DSGS should be designed to be accessible to as many customers as possible, including from different geographies, income levels, and LSEs, and should be inclusive of both BTM and distributed IFOM resources that can support the program's goals and objectives. CESA is concerned about proposals to restrict eligibility for DEBA and DSGS, particularly prohibiting customers eligible for the Self-Generation Incentive Program ("SGIP") from participating in DEBA and prohibiting most IOU customers from participating in DSGS.

a. Eligibility for DEBA should not be tied to the broad eligibility to other programs such as SGIP, but rather, the consideration should be around the incrementality of claimed incentives.

In the workshop, CEC staff raised concerns about ensuring that DEBA funding goes to customer segments that are not receiving funding from other sources. One source of funding that was discussed is the Self-Generation Incentive Program ("SGIP"), with staff suggesting that residential customers that are *eligible* for SGIP be excluded from the DEBA program. This suggestion seems to stem from future funding for SGIP that has been proposed in the California State Budget for residential customers across California. However, as explained further below, CESA recommends that the CEC revise its proposal on BTM energy storage eligibility based on its eligibility to programs like SGIP because:

- SGIP funding is currently limited, and the additional proposed funding from the Governor and Legislature is both uncertain and more narrowly targeted; and

- DEBA funding can drive BTM energy storage systems to be dispatchable and responsive to emergency needs in contrast to the more general operational requirements for otherwise SGIP-funded systems.

Traditionally, SGIP has been a program funded by CPUC-jurisdictional ratepayers through the Public Purpose Program ("PPP") charge, with eligible customers being CPUC-jurisdictional electric and gas ratepayers. However, in 2022, Governor Newsom proposed to allocate taxpayer funding to SGIP and to expand the program to all customers across the state, including previously ineligible customers of POUs. This expansion in eligibility was codified in statute by Assembly Bill ("AB") 209, along with the addition of solar as an eligible SGIP technology and the split of future SGIP funding: 70% for low-income, residential solar + storage and 30% for residential energy storage (no income restrictions). The 2022 budget did not appropriate any funding for SGIP, but $900 million in funding was proposed by Governor Newsom for inclusion in the 2023-24 budget.

Since the $900 million was proposed in Summer 2022, California's overall budget forecast has been significantly reduced, with the state facing a budget deficit this year. Therefore, Governor Newsom's proposed January 2023-24 Budget containing significant cuts, reducing SGIP funding by $230 million to $670 million, which the Governor proposes to allocate entirely to low-income customers.[2] CESA understands the desire to focus SGIP funding on these communities that have traditionally faced many barriers to clean energy and energy storage adoption and can benefit significantly from electric bill reductions and electric resiliency. However, the focus on low-income customers and DACs will significantly limit the number of customers that will be eligible for this future SGIP funding. Additionally, given the relatively high incentive (likely above $1.00/Wh)[3] that is needed to spur adoption of solar + storage in these communities, there will be fewer MWs of resources deployed per dollar spent compared to previous SGIP funding cycles that provided incentives at rates between $0.15/Wh and $1.00/Wh.

For customers that are eligible for SGIP currently, much of the energy storage funding has been exhausted. Currently, there are five energy storage budgets administered across four program administrators ("PAs"). The two budget categories focused on non-residential customers, Large-Scale Storage and Non-Residential Equity, either have waitlists or are closed across all of the PA territories.[4] The residential budget categories, Small Residential and Residential Equity, are open, but the majority of general market residential funding has been spent, incentives are now low ($0.15/Wh),[5] and uptake in low-income communities/DACs has been low due to numerous barriers the CPUC is seeking to resolve.[6] The Equity Resiliency Budget is open in three of four PA territories, but that budget category targets a very specific subset of customers. [7] Therefore, CESA sees great potential in DEBA being able to provide much-needed bridge or gap funding for segments without SGIP funding, or sufficient incentives, particularly in the non-residential segment, where SGIP incentive levels have not spurred energy storage adoption and deployment.

Across the entire SGIP Program, operational requirements are flexible, with all energy storage systems needing to meet minimum cycling requirements and non-residential systems being required to reduce greenhouse gas ("GHG") emissions to a certain level compared to previous electric consumption. While these requirements ensure SGIP systems meet the program's grid-support goals overall, there is no particular dispatch schedule systems need to follow to receive SGIP funding. Therefore, systems and systems may or may not be available or respond during a

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[2] Governor Newsom's January Budget Proposal on Climate Change Items at 46. Available at: https://ebudget.ca.gov/2023-24/pdf/BudgetSummary/ClimateChange.pdf

[3] The specific incentive level for this new funding is currently being discussed at the CPUC in Rulemaking 20-05-012. However, many parties submitted comments on December 2, 2022 suggesting incentive levels for low-income customers above $1.00/Wh in order to fully cover energy storage costs.

[4] *See* SGIP Budget Data as of February 13, 2023. Available at: https://www.selfgenca.com/home/program_metrics/

[5] Ibid.

[6] *See* the *Assigned Commissioner's Ruling Seeking Comments on Improving Self-Generation Incentive Program Equity Outcomes and Assembly Bill 209 Implementation* submitted in CPUC Rulemaking 20-05-012 on October 26, 2022.

[7] *See* SGIP Budget Data as of February 13, 2023. Available at: https://www.selfgenca.com/home/program_metrics/

specific grid emergency. In contrast, systems receiving funding from DEBA will be dispatchable and obligated to respond during grid emergencies, creating a more reliable fleet for these events.

Given the different goals of DEBA versus SGIP and the fact that SGIP funding is limited, CESA recommends that as many customers as possible, including customers eligible for SGIP, be eligible for DEBA as well. It should be up to the customer to decide which program works best for them based on the incentives available and the requirements for receiving those incentives. Customers that would like to contribute more (*e.g.*, by responding to grid emergencies) in exchange for a higher incentive or preferable program should be able to do so.

In so doing, the CEC should affirm and clarify that DEBA is a technology deployment program/incentive but not establish eligibility for DEBA based on mere eligibility for other DER programs such as SGIP. Rather an incrementality framework should be put in place.

b. Eligibility for DSGS should be broadened for all IOU customers given the opportunity to test new program designs and the potential complementary nature with other CPUC-jurisdictional DR programs.

During the workshop, staff discussed the opening of DSGS beyond POU customers through AB 209, which states that "Eligible recipients may include all energy customers in the state, except those enrolled in demand response or emergency load reduction programs offered by entities under the jurisdiction of the Public Utilities Commission."[8] However, CESA was disappointed to see that the CEC is considering only opening DSGS to only a very small subset of IOU customers: water agencies and customers with backup generators. It is unclear how the CEC envisions the participation of CCA customers in the program, given that their customers are IOU distribution customers. This aspect of the proposal was made in spite of the CCAs having expressed a clear interest in participating in DSGS.[9]

CEC staff seems to be concerned about having DSGS compete with CPUC-jurisdictional DR programs. However, CESA believes that DSGS poses an opportunity to add incremental resources to our Strategic Reliability Reserve that would otherwise not participate in CPUC programs. The design of DSGS and the proposed modifications offer a unique way to provide emergency reliability services that differ from CPUC programs, particularly DSGS Option 3. For example, ELRP provides energy payments for incremental load reduction but does not provide any capacity payments. On the other hand, IOU DR programs may provide capacity payments (*e.g.*, Base Interruptible Program, Capacity Bidding Program, DR Auction Mechanism), but these programs often require CAISO market integration, which is

[8] AB 209 (2022) Sec. 15.

[9] *California Community Choice Association's Comments on the Proposed Draft Program Guidelines – Demand Side Grid Support (DSGS) Program, First Edition* submitted on July 29, 2022 in CEC Docket No. 22-RENEW-01.

a barrier for many customers given the difficulties of participating in the CAISO market. As mentioned by Vice Chair Gunda, DSGS and DEBA provide an opportunity to pilot different ideas on providing emergency reliability. To this end, CESA believes that a DR program that provides a capacity payment and an out-of-market participation pathway is an important design to test, particularly as it relates to BTM energy storage resources.

As expressed in other venues, CESA sees gaps in the current suite of DR programs and participation pathways in terms of truly realizing the potential of storage-backed DR resources by: (1) recognizing and compensating exports in baseline calculations and in qualifying capacity ("QC") valuation methodologies; and (2) encouraging frequent dispatch due to reduced or eliminated customer attrition effects. To CESA's knowledge, all CPUC-jurisdictional DR programs and mechanisms fall short in these two regards, with dispatch and operational requirements designed to the lowest common denominator to encourage greater customer enrollment and participation and with metering and performance evaluation "zeroing out" exports in baseline and settlement calculations. The ELRP advances the role of energy storage through an incremental load reduction ("ILR") methodology and the consideration of device-level metering for certain IOUs, but this program is still limited as a voluntary energy-only program and has caps on dispatch hours and availability. If DSGS is designed in ways to address gaps or shortcomings from the current suite of DR programs, such as in requiring or encouraging more frequent dispatch response and recognizing exports, the CEC should be less concerned with competing with or duplicating CPUC-jurisdictional DR programs, such that eligibility should be broadened to all IOU/CCA customers.

Additionally, in order to truly test any new model, its effectiveness, and customers' preferences, as many customers should be eligible as possible. For this reason, CESA encourages the CEC to allow all CPUC-jurisdictional customers to be eligible, except those enrolled in another DR program, as stipulated by AB 209. Allowing more customers to be eligible will also allow additional MWs to be added to the Strategic Reliability Reserve more quickly, which will help to prevent rolling blackouts in the case of extreme conditions in 2023 and 2024. Otherwise, if only a limited set of other customers are eligible, additional time will be needed to enroll customers that are harder to reach to add additional MWs to the program, given the inherently limited potential of this group.

III. <u>DEMAND-SIDE GRID SUPPORT COMMENTS</u>.

Overall, CESA supports many aspects of the current DSGS Program, including the Option 3 capacity payments structure. Similarly, CESA supports the modification of the Option 3 performance calculation to net the incentive amount based on the full dispatch period. While largely supportive of the DSGS as proposed, CESA highlights several key concerns and recommendations in the following sections.

1. **Third-party aggregators should be eligible to be DSGS Program Providers.**

In the Workshop, staff presented a proposal to allow third-party aggregators enroll directly with the DSGS Program Administrator (either the CEC or another PA), which CESA strongly supports. Aggregators will be critical for the functioning of DSGS, as these parties have expertise in finding and enrolling customers in DR programs, which will substantially increase DSGS participation. Additionally, aggregators are typically the parties that dispatch DERs/DR resources in response to an event call, as most customers do not have the time or technical expertise to follow an event call on their own.

Given that DSGS will not be an LSE-specific program and is funded by taxpayers, CESA believes that it would be very beneficial for the program to be administered on a statewide basis. With this, it will be more streamlined and simpler to have third-party aggregators enroll directly with the PA, instead of going through an LSE as an additional step, with no benefit to reliability. This will also allow aggregators to create portfolios across LSE territories, providing additional flexibility and the potential for additional DSGS enrollment, as small LSEs without enough customers to create an aggregation of sufficient size can be added to a larger aggregation of customers from other areas.

2. **DSGS Option 3 should have an out-of-market participation pathway, with some market-informed day-ahead price trigger.**

As highlighted in CESA's comments on DEBA in response to the RFI, "market participation is not the only way to elicit emergency response. CAISO's 2022 Summer Report estimates that 1,200 MW of non-market resources, including load reduction and exports from customers participating in ELRP, DSGS, load-modifying DR, and other programs, were provided during September 6, 2022 when the CAISO triggered an EEA 3 event."[10] In their comments, Sunrun and Leap also highlighted that only 2% of customer bases that could be providing DR actually enroll in the market.[11]

Currently, BTM DERs participate in the CAISO market via Proxy Demand Response ("PDR"), a market product that provides compensation for load reduction at a customer site only. This wholesale market participation pathway does not recognize the incremental export capacity that could be provided by these resources, and limits market contributions from facilities with low loads during times of grid constraint, like schools and commercial facilities that do not operate in the evening or on weekends. Currently, the Distributed Energy Resource Provider ("DERP") model compensates for exports, but this pathway has not been used by developers given that there are few

[10] CAISO "Summer Market Performance Report September 2022" November 2, 2022, at 109. Available at: http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf
[11] *Sunrun and Leap Proposal - DER Program Design* submitted on January 26, 2023 in in CEC Docket No. 22-RENEW-01 at 3.

to no DR programs that allow for participation via DERP, the pathway is not eligible for RA, and it requires interconnection via the Wholesale Distribution Access Tariff ("WDAT"), which is a much more complex and expensive interconnection process than the more familiar and streamlined Rule 21 process for most DERs and customers. There are also market enrollment barriers, including the burdensome share-my-data process, as outlined by Sunrun and Leap. [12]

Therefore, CESA fully supports the inclusion of an out-of-market participation pathway. We believe that a market-informed event trigger is reasonable and a good way to generally measure the needs of the electric system. For storage-backed resources, CESA believes that a price-based trigger or Flex Alerts (or non-CAISO BA equivalent) could be used as triggers instead of a full EEA since storage-backed DR can be dispatched more frequently and is much less sensitive to event fatigue, given that customers experience little to no change in their day-to-day electric usage and typically only the storage device is responding to event calls. Therefore, these resources can be used outside of explicit energy emergencies and instead during times of grid stress to prevent the declaration of an EEA in the first place.

In terms of the specific wholesale price trigger, CESA previously proposed $750/MWh in January 2021 testimony in CPUC Rulemaking ("R.") 20-11-003 regarding the ELRP, premised on the fact that ELRP would operate outside of the RA framework to meet an "effective" planning reserve margin ("PRM") and based on observed day-ahead prices during extreme heat days in August and September 2020 (*i.e.*, 97th percentile of prices).[13] If updated with price analysis from extreme heat days in September 2022 and/or if a lower percentile is deemed appropriate to encourage more frequent dispatch (*i.e.*, 95th percentile, or around $500/MWh, according to CESA's analysis of 2020 heat wave events), CESA believes that a price trigger threshold for dispatch at $500/MWh to also be reasonable. Regardless, the broader point being that CESA believes that the non-market-integrated participation model can and should be pursued, with price triggers set upon the CEC's review of past extreme weather events and its desire for the frequency of potential dispatch and availability.

In other words, in contrast to the previous DSGS guidelines that require all Option 3 DSGS resources to register as a PDR and be subject to certain bidding and availability requirements, CESA strongly urges the CEC to establish a non-market-integrated pathway, especially as a means to procure storage-backed DR where the current suite of DR programs falls short. With a market-informed day-ahead price trigger in place, any concerns about visibility to the CAISO market can be addressed, knowing that the MW amount of DSGS-enrolled resources would be committed to respond if certain grid and market conditions are forecasted. Furthermore, any purported concerns about "interfering" with the RA market is also addressed by the fact that many BTM storage resources do not participate in the RA Program to begin with due to all the aforementioned policy,

[12] Ibid.
[13] *Opening Testimony of Jin Noh on Behalf of the California Energy Storage Alliance* (Exhibit No. CESA-001) submitted on January 11, 2021 in R.20-11-003 at 17-20. Available at: https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2011003/3324/359864004.pdf

valuation, and market integration barriers.[14] If the CEC has concerns about the non-market-integrated approach for DSGS Option 3 resources, which were not expressed at the Workshop, CESA requests that the CEC detail those concerns and issues in order to work toward a solution.

3. Sub-metering should be allowed to measure DSGS event response for device-backed resources.

For all payment options, CESA suggests that sub-metering be allowed for the measurement of DSGS event performance for device-backed DR, particularly storage-backed DR. This is already allowed in ELRP, and if similarly extended to DSGS, would create a more accurate measurement of DSGS performance for device-backed resources. For these resources, DR becomes fundamentally not about customers reducing electric usage, but instead about the dispatch of a device, and therefore DR programs and/or the CAISO market should directly measure the output of the device. This is done in recognition that any incremental storage discharge or reduction in EV charging, air-conditioning use, water heating, or other device-controlled loads would have otherwise been electricity consumption from the grid. Sub-metering offers a way to measure the DR contributions of devices, including energy storage and EVSE, more accurately. Sub-metering creates more accurate baselines of typical storage or device performance, with easier calculations for incremental load reduction above what is typically used on non-event days. Certain resources with submetering may require different types of baselining. Additionally, accurate submeters already exist, with ANSI standards available for non-residential systems and evidence of accuracy for existing residential sub-meters.[15] Recognizing this, the CAISO already has sub-metered measurement and performance settlement using the Metered Generator Output ("MGO") methodology, and, the CPUC has allowed for submetering to be used in the ELRP for Group A.4, Virtual Power Plants ("VPPs") and Group A.5, Vehicle Grid Integration ("VGI") Aggregations. CESA supports the continued use of sub-metering in DSGS. Given the availability of existing models, such as the CAISO MGO and ELRP, CESA believes that sub-metering can be readily incorporated into DSGS as well.

4. Visibility concerns should be substantiated by CAISO and LSEs.

During the Workshop, the CEC raised concerns surrounding the lack of visibility into customers and BTM systems by the local LSEs, IOUs, and CAISO.

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[14] To illustrate, less than 1% of customers in any of the Demand Response Auction Mechanism ("DRAM") procurement cycles included battery storage. Outside of DRAM, it is hard to ascertain specifically the proportion of DR-related RA resources include battery/energy storage. *See* Nexant's 2022 DRAM Evaluation Report at 5. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M490/K475/490475883.PDF

[15] See *DR Emerging technology (DRET) Tesla Battery Study Results* published by PG&E at 2: "Load impacts estimated using household-level smart meter data were similar to those calculated using battery end-use data, with less than a 1% difference between the impacts on average."

First, CESA understands that the CEC may have a concern around verification of customer enrollment in other LSE DR programs, given that dual participation is prohibited in DSGS. Therefore, coordination with the LSE may be needed to confirm a lack of enrollment in these LSE programs. CESA understands that systems will need to be in place for coordination between the LSEs and the CEC or third-party DSGS program administrator. We agree with Sunrun and Leap that a "live spreadsheet, wherein aggregators would record relevant potential customer details and the LSE would confirm whether the customer is enrolled in an existing program by notating as such in the spreadsheet,"[16] would be a very useful tool that could aid in coordination. In the long term, the CEC could integrate this information into a broader tool, like the CEC's MIDAS platform, where all LSEs could upload when customers enroll in programs. However, the development of these platforms will take significant amounts of time, and interim solutions will be needed.

Second, in terms of visibility that is needed for real-time operations, CESA believes that LSEs, the IOUs, POUs, and CAISO should outline their visibility needs so that they can be explicitly addressed by the CEC. At this time, it is difficult for stakeholders like CESA to respond to these concerns and outline potential solutions without a better understanding of the problem definition. For example, CESA assumes that the visibility concern is not related to individual device or customer level capabilities, response, or status, which is a level of granularity that the CAISO likely does not want or could handle. Considering that the CAISO sets minimum participation size requirements for either the PDR or Non-Generator Resource ("NGR") models at 100 kW, such granular level of visibility is not required for market participation, nor is it likely that the CAISO optimization engine could even make sense of this individual level of information. Presumably, the key consideration for the CAISO is around the interface of the transmission and distribution systems, which appears to be a broader issue not specific to DERs on how the CAISO needs to coordinate with the IOUs as distribution system operators. Rather than guessing at the questions and concerns here, CESA requests further detail on definition of the visibility concerns. Once clarified and known, the CEC should then work with these stakeholders to address the specific concerns raised. CESA would support a workshop or additional commenting opportunity for stakeholders to provide feedback on the list of issues raised by the LSEs and/or CAISO.

IV. <u>DISTRIBUTED ELECTRICITY BACKUP ASSETS PROGRAM COMMENTS</u>.

At this stage, much of the DEBA program design is still up in the air and requires further definition and detail. Based on the proposals shared at the Workshop, CESA believes that the initial DEBA program design is moving in the right direction in some respects but is not workable for all technologies and use cases, potentially overlooking an opportunity to cast a wide net and deploy BTM technologies and resources in particular.

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[16] *Sunrun and Leap Proposal - DER Program Design* submitted on January 26, 2023 in in CEC Docket No. 22-RENEW-01 at 4.

1. **CESA supports the DEBA Summer 2023 Challenge Grant, but BTM participation pathways must be clarified.**

CESA is supportive of the creation of the Summer 2023 Grant Challenge. In our initial comments on DEBA, we suggested using a GFO Model for IFOM energy storage systems and multi-customer microgrids. The GFO model works particularly well for these larger projects, which can be evaluated on an individual project basis where the key project qualities can be considered and weighted. A wide variety of projects can also be considered in the GFO, given that GFOs can be technology neutral, and parties have the opportunity to shape their funding application to meet the project needs. CESA also agrees that a GFO can be launched relatively quickly compared to other more programmatic models, which will require more time to implement. Whereas a competitive solicitation would require more in-depth evaluations and modeling beyond the typical activities of the CEC, the GFO is something that the CEC is very familiar and experienced with due to its extensive history as a grant-providing agency.

However, the GFO model is not as well suited to BTM resources, which are often too small to be considered within a GFO process and complicates the customer acquisition and evaluation process. CESA elaborates on this further below, but we continue to recommend the development of a DEBA incentive program for BTM resources. At the same time, CESA does believe that BTM resources should be eligible for the Summer 2023 Grant Challenge. To this end, clarifications should be made surrounding the ability of portfolios of resources to apply for the Summer 2023 Grant Challenge, allowing for aggregations that, for example, meet a minimum portfolio size to apply (*e.g.*, 0.5 MW). This can allow for BTM systems to participate without the CEC having to process significant numbers of small applications. At the same time, there will likely be less specificity surrounding the customer site for these projects, given that aggregations typically enroll customers on a rolling basis and after a contract is signed for a particular aggregation size and operational profile.

2. **GFO evaluation criteria should be further developed around a transparent and streamlined points system to apply weights.**

CESA believes that the scoring criteria for the Summer 2023 Challenge and any future GFOs should be transparent to applicants. This will signal to industry and stakeholders which project attributes are sought and most competitive. CESA supports the inclusion of the initial criteria proposed by the CEC at the Workshop, which represent a good starting point and set of elements the CEC should look for in a DEBA project, with modifications in line with CESA's comments on November 30, 2022 that aimed to translate key project attributes into sub-category and total points.[17] In particular, CESA appreciates the inclusion of resource longevity in the set of criteria since DEBA investments to long-lived assets will position DEBA resources to not only support near-term

[17] *Comments of the California Energy Storage Alliance on Request for Information on Clean Energy Resources for Reliability* submitted on November 30, 2022 in CEC Docket No. 21-ESR-01 at 4-7.

reliability needs but also long-term capacity needs, such as in supporting the transition away from the Diablo Canyon Nuclear Power Plant ("DCPP") and legacy gas-fired resources.

However, CESA believes that the CEC should place weights on the elements, given that some should be prioritized over others. For example, CESA believes that cost, capacity, and readiness should be prioritized over other attributes, given their importance to the success of DEBA as a program that provides electric reliability. Absent these details on not only the weights but also the translation of specific criteria to points, it will be difficult to compare and evaluate project submissions. The capacity criterion, for instance, should enable comparison of a 4-hour dispatchable resource with a 12-hour or 24-hour resource. Overall, transparency in this way will signal the key desired attributes of projects for the grand challenge to inform high-quality and best-fit grant application submissions.

See an illustrative example for how point weights can be distributed below, which we submitted in our previous DEBA comments:

Point Category	Point Sub-Category	Scoring Method	Project Metrics	Sub-Category Points	Total Category Points
Distribution-Connected Asset	MW Deployed	0.5 point per MW	8 MW	4	8
	MWh Deployed	0.5 point per 4 MWh	32 MWh	4	
Project Location	Location in DAC	Yes/No (1/0)	Yes	1	2
	Location in Low-Income Community	Yes/No (1/0)	No	0	
	Location in HFTD	Yes/No (1/0)	Yes	1	
Grid Services	Energy Deliveries 4-9pm in Local Capacity Area	Yes/No (3/0)	No	0	1
	Resiliency	1 point per 4 hours islanding capability	4 hours	1	
Project Delivery	Viability Risk Score	Qualitative 1-5 rating (5 = most viable)	3	3	4
	Timing	Summer 2023 = 5 Summer 2024 = 4 Summer 2025 = 3 Summer 2026 = 2 Summer 2027 = 1	8/1/2027 COD	1	
				Total Points	**15**
				DEBA Funds Requested	**$11M**
				Final Score (Points/$1M)	**1.36**

3. An incentive-based model is still needed for BTM resources.

In our initial comments on DEBA, we emphasized the importance of an incentive-based approach, given that "all in all, an upfront and transparent incentive is straightforward to understand and immediately bankable and allows funds go out quickly instead of waiting for a collective evaluation of all RFP/GFO applications."[18] Generally, BTM projects are developed by building a

[18] *Comments of the California Energy Storage Alliance on Request for Information on Clean Energy Resources for Reliability* submitted on November 30, 2022 in CEC Docket No. 21-ESR-01 at 8-9.

value stack for the customer, where all elements are taken into consideration upfront in order to create a viable business and/or financing plan. In these models, elements including customer electric bill savings, net metering credits, potential DR revenue, and available technology or customer incentives are taken into account. The customer and BTM developer/installer can then evaluate whether the investment makes financial sense. However, in a GFO structure or model, it is not guaranteed that funds will be awarded to any particular project or aggregation, making it hard to accurately model the finances for customers and reducing the likelihood of investment. This is why DR aggregations are often awarded contracts before individual customers are enrolled in the aggregation. That way, the aggregator can be sure that the offered incentive or DR payment is guaranteed for that customer.

Therefore, CESA continues to recommend a clear incentive amount in $/kW or $/kWh be provided for BTM systems. As expressed in our November 30, 2022 comments, we stand by our proposal for a $0.50/Wh incentive level for BTM energy storage resources and a $1/W incentive for BTM renewable generation resources.[19] Recognizing the difficulty of setting a single incentive level that is workable for all technology types, including energy-limited resources like storage and non- or less-fuel-limited resources like generation, CESA still based our recommendation on the overarching MW goals of the Strategic Reliability Reserve, as well as on market deployment trends observed in SGIP at different incentive levels.

CESA understands that the creation of this type of program will require additional time, given that additional program infrastructure will be required compared to the GFO. However, we believe that this will be a more fruitful approach to enroll these resources for Summer 2024 and beyond. Therefore, we recommend that the CEC outline a program in the initial Draft Guidelines released this March, with a clear timeline for program rollout in late 2023 or early 2024.

4. DEBA resources should not be precluded from providing RA.

During the Workshop, the CEC expressed concerns surrounding the interactions between DEBA/DSGS and the RA Program, particularly for DEBA. The concerns seem to be that projects participating in DEBA will be receiving sufficient incentives to forego participation in the RA market, thereby reducing the resources available to the CAISO and the grid on a daily basis. CESA understands this concern, given that the RA program is how we ensure regular resource sufficiency for the grid, and RA obligations ensure that resources are available both before and during emergencies. CESA believes that building up the long-term RA pipeline should be a priority for meeting California's long-term reliability needs.

However, CESA does not believe that DEBA is inherently in conflict with the RA Program. There are many factors that pose a barrier to RA participation. For BTM resources, barriers include required market participation, a lack of counting of exports, a burdensome and expensive qualifying capacity methodology in the load-impact protocols, among others. Some of these issues are being

[19] *Comments of the California Energy Storage Alliance on Request for Information on Clean Energy Resources for Reliability* submitted on November 30, 2022 in CEC Docket No. 21-ESR-01 at 8-9.

actively discussed at the CPUC but have not been resolved yet.[20] However, even IFOM resources have faced barriers to participating in RA, especially local distribution-connected resources, which include:

- **Challenges in accessing transmission plan deliverability ("TPD"):** The deliverability study process is lengthy and costly and raises questions regarding whether local distribution resources need to be capable of wheeling its power to the bulk transmission system when its generation/discharge is most likely serving load locally. Waiting for deliverability-related upgrades to be built can delay projects coming online since they are unable to access RA payments until deliverability is secured. Due to the bundling of System and Local RA attributes, developing local-only resources do not qualify for RA compliance.

- **Lack of directives to procure Local RA resources:** With the CPUC's Integrated Resource Planning ("IRP") proceeding focused on system capacity needs, CESA has observed a lack of LSE incentive to procure for resources. Most Local RA procurement of new-build resources has occurred through explicit directives from the CPUC.[21] With local resources near load centers being generally more expensive to develop (*e.g.*, due to the high cost of land), most incremental RA net qualifying capacity ("NQC") procurement through IRP orders has been for lowest-cost system-only resources.

- **Lack of incentives to procure Local RA resources:** Absent specific procurement orders, LSEs currently have little incentive to bilaterally procure new-build Local RA resources with the implementation of the Central Procurement Entity ("CPE") via D.20-06-002, even with the CAISO producing Local Capacity Technical Studies ("LCTS") annually that identify Local Capacity Requirements ("LCR") and specify how energy storage can count toward these needs. In short, each LSE no longer receives one-for-one crediting of their Local RA procurement, diluting their incentive to do so. With the "local premium" for new-build preferred or energy storage resource procurement being zero or nearly zero across multiple local areas, the LCR Reduction Compensation Mechanism ("RCM") adopted via D.20-12-006 has not impacted their incentives. In cases where energy storage projects can directly bid into the CPE RFO, there are biases against long-term and more expensive energy storage contracts due to shorter-term three-year forward requirements and cost cap in place for procurement, favoring existing resources.

In sum, CESA does not see any conflict with the RA Program at the moment with the DEBA Program if its scope focuses on local distribution-connected resources. Instead, CESA views the

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[20] CPUC Rulemaking 21-10-002 on the RA program is currently evaluating changing the PDR qualifying capacity methodology based on the outcomes of a CEC-hosted working group.

[21] *See, e.g.*, PG&E's local energy storage procurement in Moss Landing pursuant to Resolution E-4909; SCE's Moorpark and Goleta area energy storage procurement pursuant to the 2013 Long-Term Procurement Plan ("LTPP") Decision (D.13-02-015) or SCE's Preferred Resources Pilot ("PRP") energy storage procurement; and SDG&E's Preferred Resources LCR energy storage procurement pursuant to the 2012 LTPP Track 4 Decision (D.14-03-004).

DEBA Program as a potentially effective bridge or facilitator to the RA Program by helping to bring on new-build Local RA preferred and energy storage resources that are not being sufficiently addressed in the IRP or RA proceedings.

In fact, DEBA poses an opportunity to bring resources online ahead of their ability to eventually secure TPD and qualify for RA. As these local distribution-connected resources navigate their way through the deliverability study process, DEBA incentives could be used to bring these resources online as energy-only resources, which would have the added benefit in moving these projects up the priority list during the TPD Allocation Process (*i.e.*, Allocation Group C) and in potentially facilitating the LSE contracting process and moving them up even further on the priority list (*i.e.*, Allocation Group A or B if contracted or shortlisted, respectively). In effect, the DEBA funds could help "buy down" the cost of potential Local RA resources and advance the procurement of Local RA resources, which as mentioned above, are being procured and developed at a much lower rate than system-only resources. Ultimately, DEBA will only provide funding to help cover the upfront costs of hardware that is being installed and will not provide ongoing revenue streams to cover operating costs. Even for upfront costs, it is unlikely that DEBA will cover 100% of these costs, nor does CESA believe that this would be an appropriate use of funds in most cases. Regardless, there will be incentives for projects to find other revenue streams to cover remaining costs not covered by DEBA, and RA is a significant and reliable revenue stream that can be pursued.

Overall, in supporting such potential Local RA resource development, the CEC will also help facilitate the transition away from fossil-fueled generation in local capacity areas, many of which are located in disadvantaged and low-income communities. CESA struggles to view the use of DEBA funds for potential Local RA resources as interfering with the RA market if such resources are not currently being procured or built to begin with. If the CEC wishes to set some parameters on the types of projects that are procured, the focus should be on helping potential Local RA resources, where critical gaps currently exist in IRP and RA relevant solicitations.

Furthermore, CESA recommends against any lockout period from the RA Program for DEBA resources. Rather than artificially keeping DEBA-funded resources as out-of-market resources, especially as IFOM resources do not have obligations or compensation for grid services as is the case for BTM resources through the DSGS or other programs, the CEC should seek to expeditiously facilitate the development of Local RA resources that can be contracted with LSEs, show up on their RA supply plans, and operate within the CAISO market. Participation in RA should be encouraged, as this will help boost California's electric supply to prevent grid emergencies in the first place and sets projects up to be long-term contributors to the electric system. Additionally, any savings in RA costs is ultimately beneficial for ratepayers, who will not have to pay as much for this capacity.

In the interim period before qualifying as an RA resource, and in the absence of DSGS as the pathway to provide grid services, IFOM DEBA resources could operate as an "RA-like" resource with similar availability requirements in the CAISO market. This could be substantiated through a contract with the CEC or with a specific LSE.

5. **DEBA resources should be allowed to support emergency reliability needs without necessarily providing supply-side RA, such as microgrid resiliency services and load-modifying RA reductions.**

Notwithstanding our comments above that DEBA resources being able to provide RA and not be subject to any lockout period, CESA also believes that DEBA resources should be allowed to support on-call emergency needs without necessarily operating like or as supply-side RA resources. Specifically, CESA believes that the DEBA Program is well-positioned to pilot and advance additional pathways to support emergency reliability needs, including the following:

- **Microgrid resiliency services:** Emergency reliability support can be provided through microgrid islanding. Such services could be provided as on-call emergency "supply" without necessarily providing generation or discharge to the grid, operating as a "collective demand response" that reduces the amount of load to be served by the bulk electric grid. While resiliency is framed as a "co-benefit" in the proposed GFO evaluation criteria, it should be also viewed as the direct means to provide on-call emergency support for the broader grid as well.

- **Load-modifying RA reductions:** The goals of the DEBA Program can also be met by reducing the RA obligations of LSEs. Both IFOM and BTM resources could operate as non-market-integrated resources with similar operational profiles as supply-side RA resources and have inverse impacts when accounting for RA obligations, yet offer potential advantages in facilitating cost-effective and quicker-to-market reliability resource development. Energy storage dispatch and discharge during the 4-9pm period, for example, would be accounted as meeting RA obligations if shown on the RA supply plan; the same profile for a load-modifying energy storage resource would be shown as reducing RA obligations if accounted for in the load forecasting process. These types of programs also alleviate issues surrounding baselining for systems that provide permanent load shifting. Some CCAs have already discussed this pathway and how DEBA could support the expansion of existing programs.[22]

CESA recognizes that the above two pathways are not formally adopted by the CPUC or CAISO, and many details need to be developed. However, as discussed above, CESA reiterates our support for the spirit of Vice Chair Gunda's statements that the DEBA Program could serve as an important test bed for different approaches and models.

[22] *Joint CCA Proposal for Clean Energy Resources for Reliability, 21- ESR-01* submitted by East Bay Community Energy and Sonoma Clean Power on December 14, 2022 in CEC Docket No. 21-ESR-01; *PCE Solar + Battery Backup Program Joint CCA Proposal for Clean Energy Resources for Reliability* submitted by Peninsula Clean Energy on December 16, 2022 in CEC Docket No. 21-ESR-01.

6. **Additional clarity should be provided surrounding the development and implementation timelines for DEBA.**

During the workshop, staff shared an outline of a timeline for the next steps of DEBA development, which include:

- Comments on the Workshop – due February 17
- Release of Draft DEBA Guidelines and a workshop – March 2023
- Final DEBA Guidelines approved – Spring 2023
- GFO released – Summer 2023
- GFO awardees announced – Fall 2023

CESA urges the CEC to include additional details on the timeline for program development and launch, including more specific details on the launch of the GFO (*i.e.*, which month for the GFO launch and award announcement) and next steps for future iterations of DEBA beyond the initial Summer Challenge GFO. There are many parties with active projects that are looking at DEBA as a potential funding source. As such, additional clarity surrounding the specific timeline for DEBA development and the launch of funding opportunities will help with communications with customers, LSEs/off-takers, community organizations, and other external stakeholders that are seeking to develop projects but need additional funding.

V. RESPONSES TO WORKSHIP QUESTIONS ON DSGS.

Most of CESA's responses to the workshop questions on DSGS are included above. They are briefly recapped here, with some areas of additional response.

1. **What structure or provisions would best support cost-effective Resource Adequacy procurement while also enabling the development and growth of the Strategic Reliability Reserve to responds to extreme events?**

For DSGS, CESA sees the ability of the CEC to add incremental resources to California's Strategic Reliability Reserve, particularly through an out of market participation pathway. We also see DEBA as an important program for building the RA pipeline. See our comments in Section III.2 and IV.4 above.

2. **How best can the Program unlock untapped DR or other stranded resources under its statutory constraints?**

As highlighted above, DSGS can provide a unique venue to unlock incremental DR resources, especially if an out-of-market Option 3 pathway is opened. This will lead to the enrollment of resources that require the steady revenue stream of a capacity payment but face barriers to enrolling in the CAISO market. See our comments in Section III.2 for additional information.

3. As aggregators and others participate in DSGS directly: What is the most effective approach for host utilities to have visibility? What would be an effective method to ensure customers are not participating in multiple programs?

See Section III.4 above for more details on CESA's response to visibility concerns. However, we believe the creation of a tool for aggregators to confirm a lack of customer enrollment in other programs will be needed. If there are other visibility concerns, the host utilities and CAISO should share their specific concerns with stakeholders so appropriate solutions can be put in place.

4. Should DSGS be provided to other use-cases in IOU territories? If so, what use-cases and how?

See Section II above. Generally, CESA believes that all IOU customers should have access to DSGS, except those enrolled in other DR programs. This will help California have access to as many resources as possible during grid emergencies. As mentioned above, DSGS has the potential to enroll resources that would otherwise not enroll in IOU DR programs.

5. What other program modifications should be considered?

See Section III for CESA's recommended modifications surrounding the addition of third-party aggregators as DSGS providers, the inclusion of an out-of-market participation pathway for Option 3, and the use of submetering to measure device-backed DSGS performance.

VI. RESPONSES TO WORKSHOP QUESTIONS ON DEBA.

Most of CESA's responses to the workshop questions on DEBA are included above. They are briefly recapped here, with some areas of additional response.

1. **How best can DEBA invest in assets for emergency load reduction without interfering in the Resource Adequacy Program or creating clean stranded assets? How can it best do both?**

See Section IV.4 above. Fundamentally, CESA does not believe that DEBA and RA conflict with each other. Instead of prohibiting DEBA resources from providing RA, DEBA should be seen as a program to unlock valuable local capacity and fill the RA pipeline for long-term electric reliability.

2. **Are the proposed program frameworks reasonable? What modifications could unlock additional resources for emergency events?**

CESA believes that the proposed GFO framework is resonable for IFOM resources and will also allow the CEC to deploy an initial $50 million in DEBA funding quickly. However, additional clarity is still needed on how BTM resources would participate in this opportunity. On top of that, CESA believes that a programmatic approach with an upfront incentive level is needed to truly unlock BTM participation in DEBA and the installation of energy storage and other demand-side resources. See Section IV.3 for additional details on CESA's proposal.

3. **Are there additional criteria that the CEC should consider when evaluating projects? How should the CEC rank or weight the evaluation criteria?**

CESA does not have additional criteria to offer at this time. Generally, the criteria as proposed by CEC reflect our recommendations from our November 30, 2022 RFI response, but we point CEC staff to those responses on potential refinements and illustrative weighting. See Section IV.2 above.

4. **What are reasonable exceptions to non-performance in an emergency event?**

With DEBA as a technology or project deployment incentive, performance considerations can be tied to requirements set in other grid-service programs, such as DSGS for BTM resources, or through contracts for IFOM resources. CESA is open to consideration of claw-backs of DEBA funding if underperformance reaches a certain threshold (*e.g.*, 85% of grid-service capacity).

5. **What level of funding is needed to spur the development of a project?**

The amount of funding needed to spur development will differ based on the type of project, particularly for IFOM projects. For this reason, CESA recommends that GFO applicants include their own requested funding amount, and applications can be evaluated based on their cost-effectiveness. The CEC may consider adding a cap on the amount of funding that can be requested or required cost share. For BTM energy storage resources, CESA recommends an upfront incentive of $0.50/Wh for storage or $1/W of generation, which would allow DEBA to unlock up to 500 MW of resources if $500 million is allocated to this BTM program.

VII. CONCLUSION.

CESA appreciates the opportunity to provide these comments on the workshop and looks forward to collaborating with the CEC and other stakeholders in this docket.

Respectfully submitted,

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