DOCKETED	
Docket Number:	22-RENEW-01
Project Title:	Reliability Reserve Incentive Programs
TN #:	249422
Document Title:	CALSSA Comments - DEBA DSGS revised proposal
Description:	N/A
Filer:	System
Organization:	CALSSA
Submitter Role:	Public
Submission Date:	3/24/2023 9:51:22 AM
Docketed Date:	3/24/2023

Comment Received From: CALSSA
Submitted On: 3/24/2023
Docket Number: 22-RENEW-01

CALSSA DEBA DSGS revised proposal

Additional submitted attachment is included below.

March 24, 2023

California Energy Commission
Docket Unit, MS-4
715 P Street
Sacramento, CA 95814

Re: Docket No. 22-RENEW-01—CALSSA DEBA and DSGS revised program design proposal

California Energy Commissioners and Staff:

On January 20, 2023, CALSSA submitted a proposal for a California Energy Commission (CEC) program design that can provide substantial behind-the-meter (BTM) battery energy storage capacity for emergency reliability services.[1] CALSSA has also submitted comments in response to CEC workshops and its Request for Information issued on November 7, 2022.[2]

In response to feedback from CEC staff, further discussion with CALSSA members, and review of other proposals submitted to this docket, CALSSA presents this revised proposal for BTM storage serving as on-call reliability resources with funding through these CEC programs.

The key changes to CALSSA's prior proposal are summarized below.

- New proposed deployment incentive structure for BTM energy storage through the Distributed Electricity Backup Assets (DEBA) program, based on the portion of power capacity (kW) that is designated as capacity for emergency reliability events and on rated duration
- New proposed structure for participation by BTM storage resources as emergency reliability resources through the Demand Side Grid Support (DSGS) program, with options to participate as 2-hour, 3-hour, or 4-hour resources
- Added provisions related to implementation and administration of the DSGS program
- Other modifications to the proposed program design, including increased maximum event limits, changes to the structure for adjustments to compensation, and addition of test events

[1] CALSSA DEBA/DSGS program design proposal, submitted January 20, 2023, TN # 248480 (CALSSA Proposal).

[2] CALSSA Comments on Lead Commissioner Workshop on Clean Energy Alternatives for Reliability, submitted Nov. 10, 2022, TN # 247391; CALSSA Responses to Request for Information on Clean Energy Alternatives for Reliability, submitted Nov. 30, 2022 (CALSSA RFI Responses), TN # 247836; CALSSA Comments on January 27, 2023, Workshop on DSGS and DEBA programs, submitted Feb. 17, 2023 (CALSSA January 27 Workshop Comments), TN # 248884.

Introduction

Recognizing that the DEBA program requires funding recipients to serve as on-call emergency reliability resources during extreme events, CALSSA proposes a DEBA funding option providing deployment incentives for BTM storage that will participate as emergency grid resources, as well as a new participation option based on the existing DSGS program framework that will optimize the reliability contribution of BTM energy storage resources. This participation option provides compensation for committed capacity, similar to the existing DSGS Incentive Option 3 (capacity payment and bid structure), but without requiring wholesale market participation. We cannot stress enough that requiring market participation would hinder the effectiveness of these programs because it fails to recognize energy exported past a customer meter, severely restricting battery operation and effectively negating most of the capacity value of the storage resource. That is contrary to the goals of the program and would render the state's emergency response activities far less effective. Customer-sited storage offers reliability benefits and eases strain on the grid both by meeting customer demand behind the meter and by providing energy to the grid.

CALSSA's DSGS grid services proposal is one pathway for DEBA-funded storage to provide emergency reliability services, which should be made available to customers of all load-serving entities in the state. CALSSA supports DEBA incentive recipients participating through other DSGS incentive options—with program modifications as proposed below—or through the Emergency Load Reduction Program (ELRP) and potentially other emergency reliability programs, if approved by the CEC. Voluntary programs like DSGS Options 1 and 2 and ELRP provide highly effective reliability resources, and they will be more attractive to some customers than programs requiring an advance commitment to provide capacity during events. Providing alternative pathways will take the greatest advantage of different customers' resources and preferences, and will maximize the potential BTM storage resources available to provide reliability during future emergency events.

All options for participation in the DSGS program should also be available for customers who do not receive an incentive through DEBA, including customers with existing batteries.

In addition to presenting proposals for deployment incentives and for a new participation pathway for BTM storage, we also recommend modifications to the existing DSGS participation options.[3]

---

[3] An attachment to this revised proposal presents supplemental information regarding customer-sited battery energy storage systems in grid reliability programs (see Attachment 1).

DEBA Deployment Incentives Proposal

CALSSA believes that BTM battery storage can serve as an important element of the CEC's efforts to bring new reliability resources online through the DEBA program. Some key advantages of BTM storage are that it offers grid capacity that can be deployed more quickly than many other resource types and will be very reliable due to the storage technology and resource management software used by storage developers.[4]

CALSSA strongly recommends that the CEC provide DEBA funding for deployment of new BTM storage resources through an open enrollment incentive program. As explained in CALSSA's January 27 Workshop Comments, that approach is far superior to a Grant Funding Opportunity (GFO) for proven, standardized technologies, which are ready to be deployed at scale and which will benefit from a simple, streamlined incentive application process.[5]

CEC staff have stated a preference for incentive levels expressed in $/kW terms. In response, CALSSA presents this revised proposal, with the following incentive structure and levels for DEBA funding for BTM storage.

Because energy storage systems can be designed to deliver a given amount of energy (kWh) at a given nominal power (kW) over different lengths of time, a structure with incentives based on power capacity (kW) must also take into account the duration over which that power can be delivered, to avoid incentivizing extremely short-duration resources. Accordingly, CALSSA proposes that the incentive level scale with duration, based on the values in the table below. One-half of this amount is paid as an upfront incentive, and the remainder is paid over a 5-year term as described below.

Duration	$/kW
0-2 hours	$565
3 hours	$675
4+ hours	$750

For battery storage with a duration of 2 hours or less, the incentive is the lowest amount shown in the table. For battery storage with a duration of 4 hours or more, the incentive is the highest amount shown. Between 2 and 3 hours of duration, the incentive should increase linearly between the value shown for 2-hour storage and the value shown for 3-hour storage. Between

[4] For example, CALSSA member Generac Power Systems submitted RFI responses describing the functionalities and reliability benefits of its aggregation software. See Comments of Generac Power Systems, Inc. to the Request for Information, submitted Nov. 30, 2022, p. 9.
[5] CALSSA January 27 Workshop Comments, pp. 7-8.

3 and 4 hours of duration, the incentive should increase linearly between the values for 3-hour and 4-hour storage.

To receive the incentive, a storage project must participate as an emergency reliability resource. When applying for the incentive, the developer or customer identifies the amount of the kW capacity that will be designated for program participation. The incentive is calculated based on the designated capacity and on the storage duration according to the manufacturer's specifications.

The second 50% of the incentive is available to be paid in 5 annual installments. To receive each annual installment, the developer or customer must demonstrate that the resource participated in good faith as an emergency reliability resource by showing average participation during the prior year's events above a threshold level of the designated capacity. CALSSA proposes that the threshold be set at 75% of the designated capacity.

If the resource fails to meet the threshold performance level on average over a given year, it does not receive the 10% incentive payment for that year. The program should allow for exceptions under which the annual portion of the incentive will be paid if there is good cause for failing to perform above the threshold.

The storage resource may change the ongoing reliability program option in which it is enrolled from year to year and may change the amount of capacity committed through the program on a monthly basis, but must exceed the annual average threshold for each year to receive that year's 10% incentive payment.

Comments:

- All DEBA-funded resources must enter into an agreement to participate in DSGS, ELRP, or other reliability programs approved by the CEC, for a term of 5 years or other length as determined by the CEC.
- The current proposed DEBA incentive is in $/kW terms instead of $/kWh terms in response to feedback from CEC staff. CALSSA continues to believe that providing incentives in $/kWh terms is preferable for storage assets, but incentives based on a combination of $/kW and resource duration can work.
- The recommendation to have the incentive value scaled between shorter- and longer-duration resources reflects the relative value of these resources as grid emergency resources. Shorter-duration resources will dispatch during the highest-value hours; longer-duration resources do the same and will continue to provide capacity over a longer, lower-priced period.
- Customers and aggregators will be incentivized to commit a large amount of capacity to the program because doing so will provide greater compensation, but the program

should not require the entire nameplate battery capacity to be committed. Customers should be able to reserve an amount of capacity for their own use such as for backup. Without that flexibility, enrollment will lag substantially. This proposal accounts for the need to reserve some capacity for customer use by paying the incentive on a subset of the full installed storage capacity.

- The incentive should be set at a level that will ensure that new deployments accelerate, to achieve the program goal of providing on-call resources to serve California's grid during extreme events.
- CALSSA previously recommended that the DEBA incentive level be set at $250/kWh to $300/kWh based on installed capacity. SGIP incentive levels are currently at $250/kWh for some large-scale storage customers, and that level is lower than needed to support the market segment, as shown by the slow pace of adoption.[6] Residential incentives for the general market in a range of $250-$300/kWh is likely to spur interest and greater deployment. For comparison, $850/kWh for equity projects in the SGIP program drove storage deployment effectively. The incentive levels CALSSA proposes here are lower than the levels we believe are needed to drive more rapid deployment because the incentive is based on a subset of battery capacity, and if the CEC aims to accelerate deployment, CALSSA recommends that it consider basing the incentive on installed capacity rather than a designated portion or increase the $/kW incentive rate.
- The incentive level should be set with recognition that there needs to be enough certainty about compensation to enable investment in storage equipment, and that having a higher proportion of CEC funding contingent on performance reduces certainty.
- The level of the DEBA incentive can be evaluated for potential future adjustment after initial program experience.

DSGS Grid Services Program Proposal

Summary of New DSGS Option for BTM Storage Resources

CALSSA proposes a new program option through which aggregated BTM storage resources may serve as grid reliability resources, providing compensation for committed capacity, without a requirement for CAISO wholesale market participation, and without additional compensation for energy discharged by participating batteries during events. This program design is meant to optimize the contribution BTM storage can provide as reliability assets, including the ability to export energy and to measure performance directly at the device level.

---

[6] See "Incentive Rates for Current Steps" at https://www.selfgenca.com/home/program_metrics/.

Many participants would participate through aggregations. We recommend that the CEC allow aggregators to participate as DSGS providers, as discussed below, to increase the capacity available through this capacity for emergency events.

This new option, similar to the existing DSGS Option 3, targets high-priced, and therefore high-need, hours, to address and help stave off grid emergencies. Under this pathway, resources may elect to participate as 2-hour, 3-hour, or 4-hour resources, with compensation scaled based on the relative value of these resources as a function of day-ahead wholesale energy market prices. Resources are dispatched when triggered by locational marginal prices exceeding $200/MWh in accordance with a straightforward set of operational requirements, as discussed further below. This approach offers greater flexibility and will enable more resources to participate in a way that optimizes their contribution to provide emergency capacity.

The compensation values proposed here assume that participants would commit to participating in DSGS for 5 years and that funding will be available to compensate participation over a 5-year term. Because both DEBA and DSGS are funded through state budget allocations and total planned funding for DSGS is limited to $295 million, ensuring that funding is available would probably require funds to be set aside in advance for enrolled participants. When a resource enrolls in the program, 5 years of funding for that resource must be set aside to ensure the program can provide compensation for the resource's committed capacity.

In addition, the Legislature, Administration, and state energy agencies should work to identify additional funds to ensure continuation of the program with broad participation after the current budget is reserved for participating projects. One potential source of additional funding is the Clean Energy Reliability Investment Plan (CERIP). CALSSA supports the CEC's proposal to allocate funding within the CERIP budget to augment resources for extreme events and urges the CEC to increase the proposed funding levels for that funding priority.[7]

Aggregators as DSGS Providers

Aggregators of customers should be authorized to participate in DSGS as DSGS providers, regardless of whether a retail supplier has enrolled as a DSGS provider in territory where aggregated resources are located.

Comments:

- The original DSGS Guidelines limited DSGS provider eligibility to retail suppliers as defined in Public Utilities Code section 398.2, except for investor-owned utilities and

[7] Erne, David, California Energy Commission, 2023, Clean Energy Reliability Investment Plan, California Energy Commission, Publication Number: CEC-200-2023-003-CMF, pp. 3-4.

community choice aggregators.[8] In a Guideline Advisory issued on September 3, 2022, the CEC expanded eligibility to aggregators of customers during the August–September extreme heat event and the state of emergency proclaimed by Governor Newsom.[9]

- Expanding eligibility to aggregators for future program years is a sensible measure that will enable more customers to participate in DSGS. Through their existing and future relationships, aggregators will expand the reach of DSGS to new customers and increase the potential capacity available during emergency conditions.
- Aggregators serving as DSGS providers can aggregate resources across retail supplier territories, bringing economies of scale and again increasing the capacity that can be offered as emergency grid resources.
- Other parties have provided input on the importance of including third-party aggregators as DSGS providers. Sunrun and Leap note that third-party aggregators already are experienced in managing programs that provide grid services to utilities and the wholesale market in California.[10] Generac observes that aggregation technology is a valuable and cost-effective reliability resource, and that in laying out that aggregators are eligible funding recipients, AB 205 shows that third-party aggregation should be encouraged in DSGS.[11] Several other CALSSA members, in addition to Generac and Sunrun, as well as Leap, offer substantial expertise in grid service programs, and the DSGS program would benefit greatly from leveraging that existing expertise.

As DSGS providers, aggregators will follow the DSGS Guidelines requirements for DSGS enrollment, reimbursement claims, and program terms.[12] Some additional provisions can be added to the guidelines to ensure that aggregators serving as DSGS providers possess the necessary technical capabilities to fulfill the role of a DSGS provider. These could include capabilities such as the following.

- Control BTM batteries through a central dispatch location
- Ensure batteries perform during program events
- Collect, securely store, process, and transmit performance data from controlled devices
- Manage customer enrollment and unenrollment
- Issue payment to customers

[8] Demand Side Grid Support (DSGS) Program Guidelines, First Edition, August 2022, CEC-300-2022-008-REV (DSGS Guidelines), p. 26.
[9] Guideline Advisory, Demand Side Grid Support Program Provisions During the State of Emergency, September 3, 2022, p. 2.
[10] Sunrun and Leap Revised Proposal—DER Program Design, March 17, 2023 (Sunrun Leap Revised Proposal), TN # 249330, p. 8 (Section I).
[11] Generac DEBA & DSGS Program Recommendations, February 7, 2023, TN # 248681, p. 3.
[12] See DSGS Guidelines, pp. 2-4, 17-24; see also Sunrun Leap Revised Proposal, p. 8 (Section I).

<u>Proposed DSGS Compensation Structure and Levels</u>

We recommend that compensation levels be set as shown in the table below.

Month	2-hour resource	3-hour resource	4-hour resource
June	$12/kW	$14/kW	$15.50/kW
July	$21/kW	$25/kW	$28/kW
August	$22.5/kW	$27/kW	$30/kW
September	$24/kW	$29/kW	$32/kW
October	$13/kW	$16/kW	$17.50/kW
Season total	**$92.50/kW**	**$111/kW**	**$123/kW**

Alternatively, the CEC may consider expanding the program to a year-round program, with resources being able to elect whether to participate for the full year or the summer season (June-October). Under that design, CALSSA recommends the following compensation levels.

Month	2-hour resource	3-hour resource	4-hour resource
January	$8.50/kW	$10/kW	$11.50/kW
February	$8.50/kW	$10/kW	$11.50/kW
March	$8.50/kW	$10/kW	$11.50/kW
April	$8.50/kW	$10/kW	$11.50/kW
May	$8.50/kW	$10/kW	$11/kW
June	$9/kW	$10.50/kW	$12/kW
July	$16/kW	$19/kW	$21/kW
August	$17/kW	$20/kW	$22.50/kW
September	$18/kW	$21.50/kW	$24/kW
October	$10/kW	$12/kW	$13/kW
November	$8.50/kW	$10/kW	$11/kW
December	$8.50/kW	$10/kW	$11/kW
Annual total	**$129.50/kW**	**$153/kW**	**$171.50/kW**
Summer season total	**$72.50/kW**	**$87.50/kW**	**$97/kW**

Comments:

- CALSSA originally proposed that the maximum event duration would be 3 hours for all resources participating through this option. We now propose to have resources elect the duration of their participation, after reviewing the proposal by Sunrun and Leap and considering the advantages that this approach offers, including that this approach will provide greater certainty to the CEC regarding the capacity that these resources will provide to support grid reliability.

- The proposed compensation amounts for 2-hour, 3-hour, and 4-hour resources reflect the relative value of resources of these durations, based on historical CAISO market locational marginal price data for 2020-2022.[13]
- The compensation levels in this revised proposal take into account several considerations, including that the value of capacity resources has increased substantially in the past few years. Sunrun and Leap cite capacity prices between $30 and $40 per month for Q3 2023 between 2023 and 2025.[14] The Public Utilities Commission's 2021 Resource Adequacy Report, which reflects contracts executed in 2019 and 2020, shows increases above or near 10% in comparison to the prior year's report.[15] The 2021 report observes that weighted average prices for system resource adequacy has been increasing at an accelerating pace between 2017 and 2021.[16] These trends continue, and existing valuation for capacity resources, though largely not publicly available, likely exceeds the values in the 2021 Resource Adequacy Report by a substantial margin. With capacity market prices increasing, BTM storage aggregations participating in DSGS through this option can provide capacity to address reliability needs cost-effectively at or even above the levels proposed here. DSGS provides a direct benefit to all ratepayers to the extent that the DSGS capacity payment is lower than the market valuation for capacity resources.
- The program would require operation according to the requirements set out below under Operational Requirements.
- Participants would be compensated the same amount regardless of the number of dispatch events, including if there are no events in a given month. Maximum event limits (below under Operational Requirements) are set at a level designed to ensure resources are available during extreme events.

---

[13] CALSSA used NP15, SP15, and ZP26 DLAP CAISO prices for this analysis of relative value of 2-hour, 3-hour, and 4-hour resources participating in a program with events in the 4:00-9:00 pm window in June through October.

[14] Sunrun Leap Revised Proposal, p. 16 (Section VI).

[15] 2021 Resource Adequacy Report, California Public Utilities Commission Energy Division, March 2023, pp. 25-28, https://www.publicadvocates.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021_ra_report.pdf; 2020 Resource Adequacy Report, California Public Utilities Commission Energy Division, December 2021, pp. 24-27, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2020_ra_report.pdf.

[16] 2021 Resource Adequacy Report, p. 28.

- Energy exported to the grid is counted in the capacity committed and dispatched during program events.
- CALSSA recommends a 5-year program term, although the CEC may wish to establish a shorter (e.g., 4-year) term depending on available funding and other considerations.
- For new storage resources participating in the program, compensation is based on committed capacity without a baseline calculation, to streamline and simplify the program, to provide certainty to participants and the CEC about compensation levels, and to encourage battery resources to cycle for the greatest grid benefit on non-event days, as described more fully below under "Baselines."[17] For existing storage resources, CALSSA recommends a baseline approach as discussed in that section under "Existing Resources."
- Aggregators, or individual participants, nominate the amount of capacity for each duration bucket (2, 3, or 4 hours) committed to the program in advance of each month. This approach allows for adjustment over the course of a season in response to increases in enrolled customers.
- Measurement of performance for each month is based on average metered battery output, as measured by the device equipment, during events over all events in that month, and compensation is adjusted for performance above or below the committed capacity as described below under "Operational Requirements," including applying price-based weighting.
- Measuring performance at the device level, versus at the site level, takes advantage of this capability of battery storage systems in order to accurately show DSGS program performance.[18] This approach also makes it possible for customers to participate in separate demand-side grid programs by allowing energy efficiency-type program performance to be measured separately.
- This proposal provides for commitments and compensation in kW terms rather than kWh terms, based on the approach in the existing DSGS Option 3. There are reasons the CEC may prefer to have resources make commitments and be compensated in terms of kWh instead, and CALSSA is open to developing an alternative approach that does so. Basing the commitment on kW prioritizes maximizing capacity (power) that will be available at the critical peak moment during emergency conditions. Basing the commitment on kWh prioritizes maximizing energy capacity and is more agnostic to battery resource and event duration.
- This proposal also seeks to balance an interest in delivering maximum capacity during the moments of most critical need with providing capacity over a period of time. Some energy storage resources have a higher ratio of power to energy, and discharge at high

[17] See also Attachment 1.

[18] Advantages of using device-level data are also discussed by Sunrun and Leap. Sunrun Leap Revised Proposal, pp. 11-12 (Section III).

power can happen over a shorter period (2 hours, for example). This is particularly true of residential battery systems, most of which are modular, with integrated inverters and batteries, meaning that adding kWh capacity necessarily increases the maximum kW power capability based on the inverter ratings. Meeting a commitment to dispatch over a longer duration means these systems will not be able to dispatch at maximum inverter power (kW) capacity. The proposed program design, in which storage resources can elect to participate as 2-hour, 3-hour, or 4-hour assets, allows for program participation to be tailored to the capabilities of different storage assets.

Operational Requirements

CALSSA proposes that the new DSGS participation option use wholesale market–informed dispatch triggers. Using energy market price–based triggers will address emergencies because prices can be expected to be high during grid emergency conditions. This approach has the advantage that it not only addresses emergencies when they arise, but also can help avert emergencies by providing energy to the grid before an emergency alert has been called, potentially avoiding the need for an alert. This approach is similar to that in the existing DSGS Option 3 but does not require CAISO wholesale market participation.

- Program hours are 4:00-9:00 pm, 7 days a week, during the program season, June 1 through October 31.[19] In the alternative approach referred to above, there would be year-round and June-October options.
- Participants must participate in all program months.
- Event days are days in which the day-ahead CAISO wholesale market prices (LMP) include prices above $200/MWh during the 4:00-9:00 pm program hours. CALSSA recommends using the DLAP day-ahead prices for NP15, SP15, and ZP26. If the CEC determines it appropriate, each publicly owned utility and other load-serving entity outside IOU territories could recommend another pricing node or other appropriate price value to use as a trigger, and may recommend a different reference price if more appropriate than $200/MWh.
- Dispatch hours on an event day are up to the 2, 3, or 4 consecutive highest-priced hours above $200/MWh during the program hours of 4:00-9:00 pm, depending on the resource's elected duration.
- CALSSA recommends that this participation option include a maximum of 35 dispatch events per program season. This would represent an increase over the existing DSGS Option 3, which sets a maximum of 60 hours per season.[20] In the alternative approach with a year-round participation option, we recommend a maximum of 35 events per

[19] DSGS Guidelines, p. 11.
[20] DSGS Guidelines, p. 13.

summer season (June-October) and a maximum of 25 dispatch events over the other months of the year. If test events are included as part of the program design, they would not count toward this maximum.

- Events and specific event hours are determined by the program rules and with reference to the day-ahead market prices, so that all providers and participants are able to identify the hours during which they are to dispatch their resources during an event day. The program could include having an entity share dispatch signals for all providers and participants, to avoid duplication of effort. Alternatively, each provider can determine events and dispatch hours independently and notify participants. The first approach is preferable, but the second is workable with clear, detailed guidelines and safeguards to ensure that there are no penalties in the event that providers or participants identify dispatch hours that differ from the CEC's determination or that of other providers and participants regarding which hours are dispatch hours.
- Performance is based on average metered battery output (kWh delivered divided by committed event duration) over program events.
- CALSSA recommends that monthly performance be calculated using a weighted average based on the locational marginal prices for each dispatch hour. This will place greater value on performance during the hours with greatest grid benefit.
- To best balance the need for accurate capacity nominations and encourage broad participation, CALSSA recommends adapting the guidelines for adjustments to compensation in the DSGS Guidelines for the existing Option 3 as follows:[21] If the participant delivered less than the committed capacity, the payment is reduced by 1.6 times the amount of the shortfall; this payment adjustment may be modified for good cause shown by the participant for the shortfall. If the participant delivers more than the committed capacity, the CEC will increase the capacity payment at a multiplier of 0.8 up to 125% of the committed capacity. The guidelines should clarify that the payment would be reduced to zero when performance is 37.5% or less of the commitment, but that the reduction to the payment may be lessened or not applied on a showing of good cause by either the provider or the participant, and that the participant will not be required to pay a penalty for a shortfall. The guidelines should also clarify that the payment is increased for delivering more than the committed capacity, up to 120% of the compensation for performance at 125% of the committed capacity, with no further increases above that amount. Additionally, the guidelines should clarify that in months with no dispatch events, performance and compensation are based on the committed capacity.
- Test events may be included in the program design, if the CEC chooses. Test events should be the same duration as each resource's elected duration. It would be appropriate to include a required test event on the last day of any month without any

[21] DSGS Guidelines, p. 10.

prior program events. In addition or instead, the CEC could provide for aggregators and other DSGS providers to call day-ahead test events at their discretion, and the CEC could also schedule and call day-ahead test events during the season.[22]

Implementation and Administration

Sunrun and Leap's proposal addressed several considerations related to program implementation and administration that CALSSA supports.

Customer eligibility:

- Sunrun and Leap support expanding DSGS eligibility to customers in IOU territories that are not actively participating in another emergency load reduction or market-integrated demand response program.[23]
- CALSSA also supports this expansion,[24] and the current proposal relies on customers outside publicly owned utility territories with BTM storage being able to participate.

Dual participation:

- Sunrun and Leap support the dual participation limitation in AB 209, which makes ineligible customers "enrolled in demand response or emergency load reduction programs offered by entities of the Public Utilities Commission."[25] To avoid ineligible customers from enrolling in DSGS, they propose an eligibility check in coordination with the customer's LSE and potentially CAISO. They also recommend an interim approach for the first year of the program, verifying customer participation in other programs after the DSGS season has ended.[26]
- CALSSA believes that to the extent allowed by statute, the CEC should expand eligibility to customers participating in other programs where performance is measured separately, e.g., where DSGS performance is measured at the level of a storage device and performance in a smart-thermostat based load reduction program is measured at the utility meter.

[22] Sunrun and Leap propose a similar approach to test events. Sunrun Leap Revised Proposal, p. 12 (Section IV).
[23] Sunrun Leap Revised Proposal, p. 9 (Section II).
[24] CALSSA January 27 Workshop Comments, p. 4.
[25] Sunrun Leap Revised Proposal, p. 9 (Section II); Pub. Resources Code § 25792(b).
[26] Sunrun Leap Revised Proposal, p. 11 (Section III).

Customer enrollment and customer terms:

- Sunrun and Leap propose a simplified enrollment process in which aggregators develop customer agreements that meet CEC requirements, including a set of listed criteria for customer terms.[27]
- CALSSA supports this approach. Simple customer enrollment terms are an important element to adoption and uptake. The enrollment process and terms should be kept as simple and straightforward as possible.

Visibility:

- To give utilities visibility into the resources ready to dispatch during DSGS events, Sunrun and Leap propose an approach similar to supply plans provided to utilities prior to delivery months, in which the aggregator provides information for each participating asset along with an aggregate nomination of dispatchable capacity. The information can also be provided to CAISO, giving both the utilities and CAISO visibility into the resources.[28]
- CALSSA supports this approach to visibility. CALSSA's proposal includes capacity commitments, and the same information can be provided to utilities as will be provided to the CEC.

Baselines

New Resources:

CALSSA recommends that the program design presented in this proposal not include baselines for new resources, and instead measure committed capacity and performance without reference to performance on non-event days.[29]

We recommend that any resource installed after the CEC approves the modified DSGS Guidelines in 2023 be considered new for purposes of having its performance measured based on discharge without consideration of a baseline. This approach is also recommended in Sunrun and Leap's revised proposal.[30]

There are many reasons for taking this approach, as discussed here and in Attachment 1, as well as in CALSSA's responses to the CEC RFI.[31]

---

[27] Sunrun Leap Revised Proposal, p. 10 (Section III).
[28] Sunrun Leap Revised Proposal, pp. 12-13 (Section IV).
[29] We do not propose eliminating baselines from existing DSGS program options.
[30] Sunrun Leap Revised Proposal, pp. 14-15 (Section V.1).
[31] CALSSA RFI Responses, pp. 17-18.

- Omitting baselines will greatly simplify the program, streamlining both program development and program participation. This will better enable resources to deploy quickly and be available to provide grid support during emergency events. The state needs resources to be deployed quickly and should seek to eliminate barriers.
- Baselines push participants to modify their use of storage resources on non-event days in ways that often will run counter to grid needs. For example, participants may opt to discharge less during the 4:00-9:00 pm window on non-event days in the days and months before an event to create a lower baseline, contributing less energy during the net peak period than otherwise. Baselines create a perverse signal that encourages customers to avoid grid support activity on non-event days.
- The need to consider and modify behavior on non-event days adds further complexity for battery management, increasing operational costs.
- Baselines add complexity and uncertainty regarding compensation, making it more difficult for developers and customers to assess the value of participation, and hampering the ability to obtain financing.
- The foregoing issues create barriers to entry for potential participants. By contrast, omitting baselines will encourage participation in the program by making both deployment and participation easier and less costly.
- Omitting baselines will also better enable customers to optimize battery use for bill savings on non-event days. This will improve project economics and make projects more viable with less funding through CEC programs, reducing the needed level of DEBA incentives and DSGS compensation. With baselines, the ability to use batteries for time-of-use rate arbitrage and demand charge reduction is greatly reduced, so much more of battery economics will rely on government funding.
- When a new storage resource is deployed through the DEBA program and committed to provide reliability services as a condition of receiving DEBA funding, that resource is incremental as a new reliability resource, and not applying a baseline best reflects that incrementality.

Existing Resources:

CALSSA recommends that for existing resources—i.e., BTM batteries installed before the modified DSGS guidelines are approved later this year—performance be measured by one of the two following baseline methods.

The CEC should consider including this proposed participation option as a DSGS option for 2023 on a pilot basis.

1. The CEC can adopt a greatly simplified methodology using assumptions about the level of battery discharge during DSGS program hours, rather than requiring individual baseline measurement and calculation for all devices.

- In this approach, the program can use a simplified baseline based on typical cycling behavior as documented in the Verdant 2020 SGIP Energy Storage Impact Evaluation. According to that evaluation, residential systems discharged an average of 37% of their capacity during summer on-peak periods, and nonresidential systems discharged an average of 14% of their capacity.[32]
- Assuming that resources cycle every day during the program season, and basing the calculation on the most typical time-of-use on-peak period of 4:00-9:00 pm, the baseline would be calculated as follows, with kWh-AC representing the storage systems' installed energy capacity:

  Residential = kWh-AC * 0.37 / 5 = kWh-AC * 0.074
  Non-Residential = kWh-AC * 0.14 / 5 = kWh-AC * 0.028

2. Alternatively, the CEC can adopt the approach recommended by Sunrun and Leap, drawing on the existing meter generator output (MGO), with exported energy and charging energy included in the baseline.[33]

DSGS Existing Options Proposed Program Modifications

CALSSA supports the CEC continuing the existing DSGS Options 1 and 2 as an alternative pathway for providing grid resources during extreme events. Flexibility and alternative pathways will lead to greater success in addressing grid emergencies by bringing a greater breadth of potential resources to bear, as different customers will be attracted to different program offerings.

We recommend the following modifications to existing DSGS options to increase their effectiveness.

Minimum Dispatch Hours

Add minimum dispatch hours to Options 1 and 2 to create a needed level of certainty of compensation for potential participants.

---

[32] Self-Generation Incentive Program, 2022 SGIP Energy Storage Impact Evaluation, Verdant Associates, October 1, 2022, p. 60, Figure 5-19, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/self-generation-incentive-program/sgip-2020-energy-storage-impact-evaluation.pdf.
[33] Sunrun Leap Revised Proposal, pp. 13-14 (Section V.1).

Comments:

- The need for some level of certain compensation is heightened for new resources to be deployed through the DEBA program: Program participation is a key ingredient in the decision to install grid resources such as batteries. If the compensation and consequences of that participation are unknown, the DEBA incentive will need to be higher than otherwise necessary to encourage customers to install resources and participate in grid service programs.
- ELRP includes minimum dispatch hours, such as the 20 hours minimum for Group A.4, Virtual Power Plant Aggregators, and 30 hours minimum for Group A.5, Electric Vehicle and Vehicle to Grid Integration Aggregators. The Public Utilities Commission observed that minimum dispatch hours create an incentive for participation because without them potential participants would not have any assurance that they would receive compensation for participating.[34]
- As for ELRP Group A.4, 20 hours is an appropriate level for minimum dispatch hours in DSGS Options 1 and 2.

Aggregators as DSGS Providers

As for the new option presented in this proposal, aggregators of customers should be authorized to participate as DSGS providers for the existing DSGS options.

Sincerely,

/s/ Kate Unger
Kate Unger
Senior Policy Advisor
California Solar & Storage Association

Attachment 1: Supplemental Information re Customer-Sited Battery Energy Storage Systems in Grid Reliability Programs

[34] California Public Utilities Commission Decision 21-12-015 (Rulemaking 20-11-003), pp. 33-34, 40.

Attachment 1
Supplemental Information re Customer-Sited Battery Energy Storage Systems in Grid Reliability Programs

This attachment provides supplemental information regarding key considerations related to customer-sited battery energy storage systems participating in grid services programs, including programs designed to address emergency reliability.

Demand Charges

Demand charges, which apply to many commercial and industrial (C&I) customers, are typically assessed on a customer's maximum site-level demand during a given monthly billing period. There are different categories of demand charges, each of which imposes a charge for that maximum monthly demand during a particular set of hours (e.g., during the on-peak TOU period) or during all hours of the day (a noncoincident demand charge). If the customer's daily maximum demand varies from 210 kW to 380 kW over the course of a monthly billing period, the customer's maximum power demand for that billing period is 380 kW. If an applicable demand charge is $30/kW-month, that category of demand charge is 380 kW * $30/kW-month = $11,400 for that month.

For example, PG&E's rate for medium-sized commercial customers, Schedule B-19, is open to customers with a maximum facility demand between 75 kW and 500 kW. It has a demand charge of $35.21/kW-month for the monthly maximum demand during the summer on-peak TOU hours plus $7.10/kW-month for monthly maximum demand during summer part-peak TOU hours and $26.46/kW-month for monthly maximum demand at any hour (the "anytime demand charge").[1] These are additive. A customer with a monthly maximum demand of 300 kW during TOU on-peak and part-peak hours (and no higher peak outside those hours) pays $20,600 per month in demand charges in the summer and $8,700 per month in the winter.[2] For customers with demand charges, using energy storage to manage those charges can result in substantial bill savings.[3] The amount that energy storage can reduce a customer's maximum

[1] Anytime demand charges are sometimes called non-coincident demand charges because they are not coincident with TOU peak hours. Within the rate schedules, PG&E calls them maximum demand as opposed to maximum peak demand. SCE calls them facilities related demand charges as opposed to time related demand charges. SDG&E calls them maximum demand or maximum on-peak summer demand.

[2] ($35.21 + $7.10 + $26.46) * 300 = $20,631; ($2.53 + $26.46) * 300 = $8,697.

[3] The Verdant Associates 2020 SGIP Energy Storage Impact Evaluation shows that nonresidential customers realize significant savings from using storage to reduce their peak or

demand varies widely depending on the size of the battery and the consumption pattern of the customer, but 50% is a reasonable estimate given a fairly spiky customer load profile and a battery sized to match the demand spikes. With a 50% reduction, the customer above could save $10,300 per month in the four-month summer and $4,350 per month the rest of the year by installing storage. To achieve this, the customer demand would need to stay below 50% of the prior maximum demand every day of the month. If the storage system misses a single 15-minute interval, it eliminates the savings for the entire billing period.

Demand Charges on PG&E Schedule B-19 ($/kW)

	Standard	Option R
Demand during 4-9 pm in the summer	35.21	3.47
Demand during 2-4 pm in the summer	7.10	1.00
Demand during 4-9 pm in the winter	2.53	0
Demand at any time	26.46	26.46

Most commercial rates have versions with reduced demand charges and increased energy charges if the customer has solar or energy storage. These are known as Option R for PG&E, Option E for SCE, and DG-R for SDG&E. These rates were originally intended for customers with standalone solar systems, which would provide low or highly uncertain demand charge savings on the standard version of the tariff given their all-or-nothing structure (a single 15-minute cloudy period could erase the whole month's solar demand-charge savings). These rates are also attractive for customers that don't have a lot of on-peak consumption (e.g., an office building that shuts down at 5 pm), and would otherwise face high demand charges for this occasional on-peak demand. Customers with storage may not use those rates because the best way to reduce the customer bill with solar and storage may be to target the higher demand charges in the non-Option R rate.

PG&E offers a rate design called Option S, which applies demand charges daily instead of monthly. This helps reduce risk and helps enable dual use cases. However, there has been very little enrollment in Option S at PG&E, and it is subject to an enrollment cap of 50 MW per schedule. The CPUC recently rejected a proposal to create Option S rates for SCE, and the structure has not been proposed for SDG&E.

---

monthly demand, and that this is the main source of these customers' bill savings from using storage. Self-Generation Incentive Program, 2022 SGIP Energy Storage Impact Evaluation, Verdant Associates, October 1, 2022, p. 73, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/self-generation-incentive-program/sgip-2020-energy-storage-impact-evaluation.pdf.

Demand Charges for California IOUs

		Demand Range for Eligibility		Anytime	Summer TOU Peak	Summer TOU Part Peak	Winter TOU Peak
PG&E	B-20	Above 1000	Standard	29.14	32.34	6.41	2.57
			Option R	29.15	3.05	0.87	0
	B-19	500-1000	Standard	26.46	35.21	7.10	2.53
			Option R	26.46	3.47	1.00	0
	B-10	Below 500		17.96			
SCE	TOU-8	Above 500	Option D	21.22	23.92		7.33
			Option E	13.46	6.73		3.04
	GS-3	200-500	Option D	19.78	23.00		8.32
			Option E	12.62	6.47		3.44
	GS-2	20-200	Option D	20.97	26.79		7.03
			Option E	12.38	7.53		2.91
SDG&E	AL-TOU	Above 20		33.38	28.19		28.83
	DG-R	Above 20		20.59	4.26		0.90

For PG&E, the majority of medium-large commercial customers are on B-19. A smaller number of customers are on B-20, but their load can be very large. Both are important to demand flexibility, because the larger number of the former offers substantial capacity, as does the smaller number of the latter. For SCE, all three schedules have significant participation. SDG&E currently only has one class of medium-large commercial customers, but a study is underway to divide it into separate classes by size.

Rate schedules are available at the following locations:

- https://www.pge.com/tariffs/index.page
- https://www.sce.com/regulatory/tariff-books/rates-pricing-choices
- https://www.sdge.com/rates-and-regulations/current-and-effective-tariffs

Because demand charges are substantially higher during the summer months, the great majority of the value of demand charge management is realized during the summer. In specific cases of some CALSSA member customers, the summer value is 75%-85% of the total value of bill savings.[4]

[4] Demand charges are typically a larger portion of the total energy bill for larger C&I customers and a smaller portion for smaller C&I customers. Where demand charges are smaller, the customer has less incentive to install storage because there is less impact on bill savings.

Here is one example of the demand charge value by month for a 250 kW/1000kWh battery on the SDG&E AL-TOU tariff:

Month	% of Bill Savings
January	2.1%
February	3.7%
March	2.9%
April	2.3%
May	2.1%
June	22.8%
July	17.8%
August	20.0%
September	18.0%
October	4.5%
November	2.0%
December	1.9%

Months that are typically included in summer emergency reliability programs carry the greatest value because of the substantially higher summer demand charges.

Baselines

CALSSA's prior submissions to this docket have presented reasons why a program design that does not rely on baseline methodologies (e.g., comparing customer net demand during the event hours to the same hours from the 10 prior non-event weekdays) to measure performance during program events will enable greater participation and larger contributions to reliability during extreme grid conditions. Baseline methodologies present several difficulties that deter program participation by undervaluing or understating event performance and creating uncertainty around expected revenue.

As one illustration of the difficulties presented by baselines, under a commercial tariff with a typical demand charge structure that has 75%-85% of bill savings value in the summer months (as described above), to optimize bill savings, the battery would discharge to reduce and flatten the load to the greatest extent possible during summer on-peak hours on all days, regardless of the level of system-wide generation capacity scarcity or other emergency conditions. This means that in a program using a baseline that compares the customer net load on event days with that on non-event days, the baseline will be based on load reduced by battery discharge on those non-event days, leaving little opportunity for additional load reduction beyond the baseline on event days. Where compensation is provided only for incremental load reduction, the customer will receive little compensation from the program, even though the battery reduces load substantially during an event. This reduces the incentive to participate in a grid services program, unless the customer forgoes demand charge management during program months to modify its baseline so that it can provide additional load reduction beyond the baseline during event hours.

One CALSSA member notes that they have several large batteries that could participate in DR/Emergency Load Reduction programs, but those batteries do not participate because of uncertainty around how much capacity they could provide during event hours due to baseline effects. On event days, facility loads such as space cooling can throw off baselines and make it difficult to model with certainty what amount of load reduction a battery can provide in comparison to the customer's baseline. Even with day-of adjustments that are allowed in customer baselines, event performance and payment is not predictable enough to outweigh potential lost customer bill savings by modifying battery behavior. As a result, the CALSSA member does not enroll these sites into DR programs and therefore does not provide capacity that otherwise could be enlisted at the most beneficial times.

Conversely, if battery performance is based on directly metered battery discharge during events regardless of battery operation on non-event days, more sites and capacity will be enrolled and participate in emergency response programs. An analysis of a medium sized commercial site in San Diego Gas & Electric territory found that replacing the baseline methodology with payment for actual discharge would have increased battery discharge by 54% during 2022 ELRP event hours. The increased certainty and value of being paid for the entire battery discharge is enough to make up for any lost customer bill savings and thus encourages greater battery discharge during event hours. While this result is specific to a single site, it is indicative that payment based on actual event discharge rather than discharge as measured by a baseline will result in greater participation and overall capacity during event hours.

Exported Energy

The CEC's DSGS program allows for energy exports to be eligible for incentive payments.[5] CALSSA agrees with this approach, and previously provided comments supportive of including exported energy to be counted in the CEC's reliability program design, in response to the CEC RFI.[6] This letter provides additional information regarding existing policies and rules that limit the ability to count exported energy in program performance, and the additional potential capacity that can be provided when exports are included.

While the DSGS Guidelines provide that energy exports can be included in the program, the design of Option 3, the capacity payment and bid structure, creates a de facto prohibition on counting exports because it requires resources to participate in the CAISO wholesale market as Proxy Demand Resource (PDR) resources. The PDR model uses a baseline methodology to

[5] DSGS Guidelines, p. 9.
[6] CALSSA RFI Response, p. 17.

calculate load reduction in response to dispatch events. The methodology states that "Meter data intervals in which there is a net export of energy, at any underlying PDR, RDRR, or PDR-LSR (Curtailment only) location, *must be set to zero (0)* when using a Customer Load Baseline methodology" (emphasis added).[7] Setting the export to zero disallows payment for energy exported to the grid during dispatch events.

This can also make it challenging for a battery aggregator to manage the resource. This is because an aggregator typically will not know in advance how much load customers will be consuming when the resource is dispatched, and therefore the aggregator cannot know how much battery capacity to commit and bid into the market. For example, if the aggregator bids 10 MW of BTM battery capacity into the market, but customers are only consuming 3 MW when the resource is dispatched, CAISO will only count those 3 MW toward the aggregator's obligation, even if the batteries discharged the full committed 10 MW. Consequently, any grid services program that requires BTM resources to participate in CAISO markets will not be able to pay sites for exported energy and will force aggregators to bid only a small fraction of their battery capacity into the market in order to avoid falling short of their obligations.[8]

PDR resources may also use the metering generator output (MGO) methodology. That methodology also disallows an export of energy to be included in measurement for compensation, as well as in baseline calculations.[9]

Additionally, if a non-market-integrated program is designed to use a CAISO baseline methodology as is, without modification, that program will similarly not pay for exported energy.

Because the PDR tariff does not count energy delivered beyond the customer's meter, BTM batteries enrolled in programs that use these baseline methodologies do not dispatch their full capacity. They are limited to reducing onsite load, cutting off the ability to discharge a frequently large amount of capacity beyond that demand level.

Any limitation to onsite load further reduces the ability of BTM resources to provide capacity during emergency events for additional reasons. First, if the customer practices energy conservation during an event, that constrains the amount of discharge that the battery can do to offset customer load. Second, some customer sites have a load profile with very low load

[7] CAISO Business Practice Manual for Demand Response V10V8, located at https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Demand%20Response.

[8] CAISO market participation imposes other burdens as well. Contracting with a scheduling coordinator and demand response provider can cost thousands of dollars every year and include a percentage of revenue from market events. Adding these costs to a participation model that uses baselines and does not credit exports further reduces the attractiveness of wholesale market participation.

[9] CAISO Tariff, section 4.13.4.2, located at http://www.caiso.com/Documents/Section4-Roles-and-Responsibilities-asof-Nov3-2022.pdf.

during program event hours. Schools are a primary example of this type of profile, with load dropping substantially at the end of the school day. Many other commercial customers also have load that falls off precipitously in the evening hours. Residential customers may also have extremely low load during peak TOU hours, and for those customers, there is little incentive to join a program that measures only load reduction.

As one example of the forgone capacity when exports are not counted, during the summer 2022 heat dome, one CALSSA member, a leading C&I storage aggregator, dispatched approximately 85 MW and 260 MWh over the 4-9 pm period on September 6. During that period, this aggregator could have dispatched about 10 MW and 70 MWh more (over 25% greater energy capacity), if not for export restrictions. This is the additional capacity that could have been provided on a single day. That amount can add up substantially over the length of a multiday extreme heat event.

Another CALSSA member provided the following model of an existing commercial site to show the added capacity that can be provided when exported energy is allowed. With participation as a CAISO PDR resource and with exports allowed and counted, this storage resource could increase discharge beyond onsite load when the CAISO wholesale price spikes as a result of increased scarcity and need.

This model is based on an actual commercial site in SCE territory.[10]

As the following table and graph show, if exports were allowed for PDR resources, this single battery resource could increase the power it can provide for reliability by approximately 30%, and it could increase the energy capacity available for discharge during an event by nearly 10%. Aggregated with other battery systems, this offers a substantial additional resource for the grid.

[10] Relevant facts about the site are:

- Size of solar and storage systems matched to load
- Commercial load for a small to medium building with fairly flat 24-hour load and total annual load of 225,829 kWh
- Solar array size 162 kW, annual production of 219,100 kWh
- Battery power capacity 30 kW, energy capacity 100 kWh
- Rates assumed in model:
    - SCE General Services Demand: TOU-G5-2-D
    - NEM 3 SCE territory Avoided Cost Calculator
    - Wholesale energy: CAISO/SCE 2023 forward curve scaled to 2021 DAM variability
    - Wholesale ancillary services not used

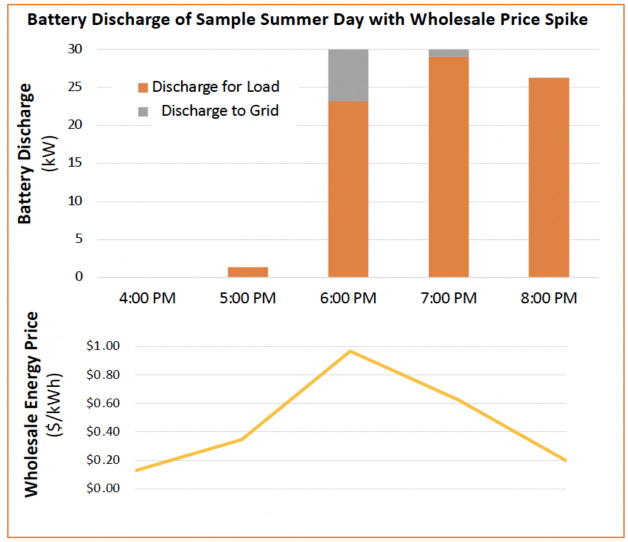
Impact of allowing CAISO Proxy Demand Resources to export.

Exporting provides additional power and capacity on top of existing RA benefits when value to customer is optimized.

- Battery offsets load during peak period most days
- When wholesale energy spikes, battery discharges additional power exporting energy to the grid
- Wholesale spikes in model align with higher NEM3 export price limiting extra value

Additional Power	
Peak 6PM power without export	23.2 kW
Additional 6PM power with export	6.8 kW
Total 6PM power with export	30 kW
Percent Increase	29.3%

Additional Overall Capacity	
Peak 4-9 capacity discharge without export	79.9 kWh
Additional 4-9 capacity discharge with export	7.7 kWh
Total 4-9 capacity discharge with export	87.6 kWh
Percent increase	9.6%



Limitations on exports from a BTM battery not only reduce the ability to discharge the capacity stored in the battery, but also place limits on the size of new batteries being deployed. Sizing of batteries, particularly in the C&I market, is typically optimized to use the largest system possible that can be physically sited at the location and deliver economic benefits beyond the cost of equipment and installation. Export restrictions limit both the optimal energy capacity and the optimal power. There is no reason to install more storage capacity and increase the power (inverter) when energy in excess of load can't be exported. This means that currently, because exports aren't compensated, batteries are being sized smaller than the available space on site. If exports were compensated, not only could existing systems provide more value (as described above), but future systems would have economic incentive to be sized larger than they otherwise would, unlocking even more capacity.

Economic decisions of this type implicate the value of grid services programs. With greater value provided through a program designed to meet grid reliability needs, there will be greater economic incentive to deploy larger battery systems, bringing greater capacity online to serve as reliability resources.