BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues.	Rulemaking 12-11-005 (Filed November 8, 2012)

COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE TO THE ASSIGNED COMMISSIONER'S RULING SEEKING COMMENT ON IMPLEMENTATION OF SENATE BILL 700 AND OTHER PROGRAM MODIFICATIONS

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In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the California Energy Storage Alliance ("CESA") hereby submits these comments to the *Assigned Commissioner's Ruling Seeking Comment on Implementation of Senate Bill 700 and Other Program Modifications* ("Ruling"), issued by Assigned Commissioner Clifford Rechtschaffen on April 15, 2019.

I. INTRODUCTION.

CESA supports the Commission's efforts to improve the Self-Generation Incentive Program ("SGIP") to more effectively achieve the program's goals of reducing greenhouse gas ("GHG") emissions, provide grid support, and transform the market for energy storage technologies. This program has undergone many changes and has incrementally improved to better align program design with program goals, but, as observed in the Ruling, certain market segments of program are seeing lower-than-expected activity while new opportunities are emerging to leverage SGIP funds to deploy energy storage systems for new and growing grid needs (*i.e.*, resiliency). Thus, the issuance of this Ruling is timely to not only implement Senate Bill ("SB") 700 and infuse the program with additional needed funds to achieve the state's long-term goals, but also to address some of the barriers faced by several segments of the energy storage market. To the degree possible, the Commission should strive to avoid making program rules and processes overly complex, while still being a sophisticated program that effectively achieves its goals.

Importantly, as program modifications are considered, the Commission should fundamentally view SGIP as a market transformation and technology deployment program that offers the flexibility, options, and reasonable incentives to achieve the other program goals of reducing GHG emissions and providing grid support. CESA supports these goals. It is important, however, to distinguish the technology-deployment orientation of SGIP from the more rigorous, complex, and prescribed nature of grid-services contracts, such as a Resource Adequacy ("RA") capacity contract which, for a high contract value and liquidated damage risk provisions, can stipulate must-offer obligations, performance criteria, etc. In SGIP, by contrast, well-intended measures to broadly promote GHG emissions reduction or grid-support goals need to also flexibly support the market transformation goal. SGIP cannot be successful if energy storage projects are not deployed. The lack of uptake and participation in SGIP highlights how the 'simple' incentive approach and incentive levels of SGIP may be insufficient to address risks, uncertainties, customer adoption challenges, or economic hurdles. By exploring avenues and developing policy in other proceedings to provide SGIP-funded storage projects with the signals (*e.g.*, via rates) or the opportunities (*e.g.*, grid-support programs or procurements), these other program goals will be more likely met while supporting the basic technology-deployment approach of SGIP. Finally, CESA supports the Commission's consideration of program modifications to direct SGIP-funded projects in smart ways to address urgent needs. To realize these use cases, CESA recommends modifications to SGIP as appropriate to drive deployment of storage systems while balancing urgent grid or customer needs as well as SGIP's established goals.

CESA does not respond to all questions but provides responses in many topic areas, as labeled.

II. <u>OVERALL COLLECTION LEVELS FOR YEARS 2020-2024</u>.

<u>Question 1</u>: What criteria should the Commission use to determine ratepayer collection levels for years 2020-2024?

<u>Question 2</u>: Based on your proposed criteria, should further collections be authorized for SGIP? If yes, at what level, and in which years?

CESA recommends that the Commission authorize the full amount of funds authorized under Senate Bill ("SB") 700. The Legislature intended for these authorized collections to "increase deployment of…energy storage systems" to achieve a number of goals.[1] In addition to customer bill savings and customer/grid resiliency, behind-the-meter ("BTM") storage has great ability to provide dispatchable grid services that provide flexibility and load shifting as the state pursues more

[1] SB 700, Section 379.6(a)(1).

aggressive GHG emissions reduction goals.[2] With program modifications, these goals and more (*e.g.*, customer resiliency) could be achieved.

Furthermore, significant amounts of BTM storage are needed to support the projected 19,992 MW of BTM solar projected to be on California's grid by 2030 (more than 12,000 MW added from 2018 to 2030).[3] Currently, between 94% to 98% of small residential storage projects are paired with solar, while 59% to 62% of large-scale storage projects are paired with solar (see Tables 2 and 3 in Appendix A), suggesting that load shifting in response to new rates is a major use case today and will likely continue to be a major use case going forward given the high levels of utility-scale and BTM solar projected to be on the grid through 2030.[4] Energy storage resources play a big role in solar integration and will likely require more than $1 billion in funding from SGIP, using conservative assumptions (see Appendix D), to support paired-storage deployments with solar. These sizing and need estimates do not account for resiliency-driven needs, which are also emerging in large MW sizes. By comparison to the California Solar Initiative ("CSI") and its budget of over $2 billion between 2007 and 2016, full authorization of SGIP through 2024 at $166 million per year represents a relatively smaller amount already in comparison to solar funding programs.

Finally, if the fully-collected amount of funds are not used, then those funds can be returned to ratepayers at the end of 2024. SB 700 explicitly stipulates this in directing that unallocated funds should be repaid to ratepayers. Not authorizing the full amount would therefore limit the potential to deploy storage systems to support state goals despite the ability to return any excess funds, hampering the Commission's ability to execute on the goals of SB 700.

<u>Question 3</u>: Should the Commission authorize the carry-over of accumulated SGIP funds at the end of 2019 for use in subsequent years?

Yes, in addition to supporting the intent of increasing the deployment of storage, these accumulated funds will be put to use to achieve the goals of the program with some modifications to

[2] See *Workshop on Proposed Reference System Plan for the CPUC's 2017/2018 Integrated Resource Planning (IRP) Process* presented on September 25-26, 2017 at p. 71. BTM storage was not optimized in the Integrated Resource Plan ("IRP") modeling, but Shift DR served as a proxy resource.

[3] CEC CEDU 2018. Final CAISO Load Modifiers Mid Baseline Mid AAEE AAPV 2018-2030. See 2017 IEPR assumptions used in the 2017-2018 IRP here: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/IEPR_btmpv_aapv_icap_and_hourly.xlsx

[4] More than 6,000 MW of new utility-scale solar PV investments were proposed in individual IRP filings by LSEs. See D.19-04-040 at p. 90. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF

overcome the barriers to certain market segments as well as to support new and urgent use cases. As explained below, SGIP may be able to play a helpful role not just in the deployment of systems per SGIP goals, but also in allowing storage to meet new or emerging needs, including resiliency.

III. FUNDING ALLOCATION.

A. Participation in Generation Projects and Budget Allocation Between Generation and Storage

Question 3: Should the Commission modify the budget allocation between storage and generation projects for funds collected in 2020-2024? If so, what allocation do you propose, and why?

CESA recommends that the Commission modify the budget allocation to make more funding available for storage projects. The rationale for the budget allocation between generation and storage projects in the decision implementing AB 1637 based on historical participation rates in the program should similarly apply here. Our review of the SGIP Weekly Report finds that 89%, 97% and 95% of SGIP funds were claimed by energy storage technologies in 2017, 2018, and 2019, respectively (see Table 1 in Appendix A). Rather than leaving funds unused, the Commission should strive to support SGIP technology deployments and authorize all the SB 700 funds toward energy storage projects. At the same time, CESA does not recommend making budget allocation decisions strictly or solely based on this rationale. For example, by this logic, the budget allocation would shift away from the Equity Budget, which has experienced little to no activity but remains an important statewide objective to support disadvantaged communities ("DACs") and low-income customers. Thus, depending on the barriers identified, the Commission should seek to balance the objectives of supporting specific technologies and/or customer segments with program modifications to boost participation while seeking to ensure funds are allocated to reflect market demand to support the program's goals.

B. Reduced Participation in Non-Residential Storage Projects and Residential/Non-Residential Budget Allocation

Question 1: What were the main drivers for the reduced participation in the non-residential storage budget in 2018?

CESA points to two critical factors that have led to reduced participation in the non-residential storage budget in 2018. First, the current incentive rates are insufficient, especially for larger non-residential projects that are subject to less upfront payments. The step-down of incentive rates has outpaced the rate of decline of energy storage costs for non-residential storage projects, resulting in projects being uneconomic, even with the inclusion of incentives.

Year	Non-ITC Incentive Rate	YoY Decline	ITC Incentive Rate	YoY Decline
2017	$0.50/Wh		$0.36/Wh	
2018[5]	$0.35/Wh	30%	$0.25/Wh	30.6%

Lazard's most recent capital cost outlook for lithium-ion battery systems only forecast an annual cost decline of 8% from 2018 to 2022.[6] GTM Research reports that battery and balance of system costs declined between 14% and 16% from 2016 to 2017 for in-front-of-the-meter ("IFOM") storage systems and forecasts future price declines by 8% to 14% annually through 2020.[7] BTM storage systems likely face the same or higher cost trends.

Second, the uncertainty of GHG emissions and operational requirements as well as pending rate designs have led to a 'chilling' effect or a 'wait-and-see' approach. CESA's members indicate that many prospective customers are waiting for new rate schedules to be implemented before investing in storage. Customers in Southern California Edison ("SCE") and San Diego Gas & Electric ("SDG&E") territories have only had a 4pm - 9pm peak period since March 2019. Customers in Pacific Gas & Electric ("PG&E") territory will be subject to a peak period of 4-9pm beginning in October 2020. With solar-plus-storage systems constituting the majority of SGIP deployments, the reduced economics for solar also reduces the economics of deploying storage pairings, as storage cannot claim the investment tax credit ("ITC") without solar, even though there may be cases where standalone storage is an appropriate choice (*e.g.*, low solar irradiation due to shading).

Beyond these factors, CESA notes that there may be other less major but still important reasons for the level of activity SGIP is seeing in the non-residential storage budget categories. With only one performance-based incentive ("PBI") project paid out since the end of 2017, CESA suspects that onerous cycling requirements may deter the development of larger non-residential projects, which can add costs to systems without necessarily added benefit. Moreover, larger non-residential

[5] All the PAs outside of PG&E opened their Step 3 in 2018.

[6] *Lazard's Levelized Cost of Storage Analysis – Version 4.0* at p. 14. https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf

[7] *U.S. Front-of-the-Meter Energy Storage System Prices 2018-2022* published by Wood MacKenzie on May 9, 2018. https://www.woodmac.com/our-expertise/focus/Power--Renewables/U.S.-Front-of-the-Meter-Energy-Storage-System-Prices-2018-2022/#gs.fXKEQqY

storage projects face longer project development cycles, which our members have indicated stem in part from the onerous process to secure SGIP funds. Every step of the application process can take months, even in the early stages to get a reservation – an issue that may at times be exacerbated by what members have reported as potentially varying processes from different Program Administrators ("PAs").[8] Finally, there may be market saturation factors in play in certain territories (*e.g.*, SDG&E) where there are fewer non-residential customers.

Question 2: What program changes should the Commission consider, if any, to increase subscription in the non-residential storage budget?

Several program changes could be explored. First, CESA recommends that the Commission provide certainty on the GHG emissions and operational requirements of the program. The uncertainty around the potential for incentive claw-backs, onerous penalty provisions, suspensions, 'praise or shame' lists, and other ideas raised during the stakeholder process in this proceeding has led to more difficult financeability of SGIP storage projects and have deterred some developers from participating in the program until there is more certainty. Second, incentive rate step-down structures by duration and size could be revised to improve the economics of storage projects and align with growing grid needs for load shifting and resiliency. This latter approach may also support system configurations that target different use-cases, such as daily solar integration, resiliency, etc.

Question 3: Should the Commission modify the budget allocation between residential and non-residential storage projects for funds collected in 2020-2024?

Yes, CESA recommends a modification to funding allocations that ensure market transformation of market segment while providing the flexibility for certain service territories to experience greater growth and deployment of storage projects given their customer composition and market drivers (*e.g.*, rates, programs, grid needs). The residential storage market, for example, has grown sharply and outpaced the non-residential market in most PA territories but have been limited by the 10% carve-out, leading to steep incentive rate step-downs as SGIP applicants exhausted each step. Rather than conducting a study of customer composition by utility service territory to better right-size the carve-out, CESA recommends a moderate allocation of funding in each step for Small Residential, Large-Scale, and Equity budget categories to preserve market growth and align incentive

[8] CESA is aware that the PAs submitted an Advice Letter including a number of streamlining proposals. The Advice Letter has been suspended by the Commission, and CESA urges that these proposals be approved. Other streamlining ideas, if developed, should be considered to provide useful conformity across PAs.

rates with that growth, in addition to a General budget category available to all project types to give the program flexibility to reflect market demand and growth trends – *e.g.*, 20% Small Residential, 20% Large Scale, 20% Equity, and 40% General.

C. Lack of Participation in Storage Equity Budget and Storage Equity/General Budget Allocation

<u>Question 1</u>: What were the main drivers for the lack of participation in the storage equity budget in 2018?

Based on member feedback, CESA believes the main barriers for minimal participation in the Equity Budget to be as follows:

- **Lack of economic value proposition for low-income customers, in part relating to structural elements of their electric service:** Many Equity Budget customers are likely exempt from TOU rates or have demand charge components that only apply to common load, which reduces the value proposition of energy storage arbitraging or mitigating these charges.[9]
- **SGIP operational requirements are challenging for Equity Budget projects:** Given the lack of economic incentives from underlying rate structures, Equity customers may find it challenging to meet these operational requirements without any material economic benefit.
- **Solar-plus-storage value proposition:** There may be limited economic value in deploying standalone storage systems to Equity customers. With the low-income solar programs (*i.e.*, DAC-SASH, SOMAH) in the process of implementation and launch, developers may be waiting for the launch of those programs to deploy the SGIP Equity Budget storage projects together with solar. Upon launch of these programs, CESA envisions that there could be more activity from Equity projects.
- **Institutional barriers and risks:** Some Equity customers may face conditions of lower creditworthiness, and lower willingness and/or wariness to spend out-of-pocket on energy investments. Such customers may thus require dedicated and customized marketing, education, and outreach ("ME&O"). Developers may be deterred from approaching customers with a more uncertain sales process as a result. Furthermore, due to 'first mover' concerns in an underserved market, developers may see some risk in 'selling' energy storage systems to eligible Equity customers.
- **Lack of (streamlined) information on eligible customers:** Developers may find it challenging to identify which customers are eligible.

<u>Question 2</u>: What program changes should the Commission consider, if any, to increase subscription in the storage equity budget?

[9] At the same time, for multi-family homes, even as tenants are exempt from TOU rates, common loads and the landlord's meter may be subject to TOU rates or demand charges.

A key program change to spur activity in the Equity Budget would be to allocate resources to dedicated and customized ME&O as well as greater 'networking' of developers with eligible Equity customers. Due to the aforementioned structural barriers, a trusted and knowledgeable 'ambassador' to these communities may be needed to facilitate opportunities for developers. Unlike non-Equity projects, developers face challenges in identifying, selling, and developing projects alone. Furthermore, other low-income or DAC-focused programs have contracted with dedicated PAs or ambassadors to support information flow and develop ME&O materials. To address this issue, CESA recommends that the Commission consider leveraging the existing ME&O activities as well as consumer protection measures of the Disadvantaged Communities – Single-family Solar Homes ("DAC-SASH") Program and Solar on Multifamily Affordable Housing ("SOMAH") programs to facilitate synergies between solar and storage deployments. Alternatively, the Commission should consider how Community Energy Navigators ("CENs"), similar to what was adopted in the San Joaquin Valley ("SJV") proceeding, could be incorporated into the ME&O activities of SGIP. Competition for these customers, to a degree, with ME&O support should be preserved to deploy storage projects for Equity customers to promote proper market conditions.

Additionally, CESA recommends that the pending GHG and operational requirements may need to be applied with more flexibility for Equity projects, or at least customized to Equity customer use cases, similar to small residential projects, where they are offered a number of deemed-compliant pathways to achieve the program's GHG and grid-support goals. For example, by virtue of being IFOM and not having onsite customer load as part of the virtual net energy metering ("VNEM") tariff, SOMAH projects would be unable to charge from the grid and could only charge from the paired solar generator, which the SGIP GHG Report showed correlations with meeting the program's GHG goals are met. If Equity projects are targeted to resiliency applications, the cycling requirements may need to be lowered or relaxed since the provision of resiliency services requires less cycling to be viable. This could amount to exempting projects of some requirements where appropriate. In so doing, the Commission should recognize not only the value of resiliency but also the environmental attributes of avoiding diesel generators as the backup solution.

Question 3: Should the Commission direct PG&E to open Step Three of its storage equity budget prior to opening Step Three of its general storage budget?

Yes, PG&E should be directed to open Step 3 of its Equity Budget without tying it to the Step 3 opening of its General Storage Budget category. There is no reason to withhold the release of Equity

Budget funds contingent on the exhaustion of funds from another market segment. The two budgets are not interrelated and should be opened independent of each other. As CESA recalls, the reason for tying the Equity Budget launch to the General Storage Budget category was to provide sufficient time for the PAs to implement Equity Budget changes to the application portal.

<u>Question 5</u>: Should the Commission modify the storage equity budget carveout for funds collected in 2020-2024?

CESA supports preserving the current 20% Equity carve-out of 2017-2019 funds and establishing a new 20% Equity carve-out from the allocation of 2020-2024 funds. With some of the changes as proposed in our responses, participation rates in the Equity Budget may increase. Within the 20% Equity carve-out, it may be reasonable to also explore Small Residential, Non-Residential, and General sub-categories to similarly allow for flexibility for funds to be directed in response to market demand but still preserve key market sub-segments.

<u>Question 6</u>: Is a modification to the equity budget incentive structure warranted? If so, what do you recommend and why?

Yes, higher incentive rates are needed in this budget category. Currently, the incentive rate is capped at $0.50/Wh pursuant to D.17-10-004. A higher starting point in the incentive rate is needed immediately, rather than waiting for the step-up mechanism to reach a level of economic viability to see any activity in the Equity Budget. In general, CESA supports the step-down and step-up mechanisms as being responsive to market demand, which works well for a dynamic storage marketplace with customers facing and responding to clear economic signals. However, such a mechanism may not work for Equity customers, who face institutional barriers and likely have longer project development cycles. Instead, for Equity customers, CESA recommends either a 100% of system cost cap approach or an administratively set incentive rate structure beginning at $0.75/Wh, which was proposed by SCE for its Energy Storage for Multi-family Affordable Housing Incentive Program in Application ("A.") 18-03-002. This $0.75/Wh rate was based on statewide SGIP large-scale project costs in Steps 1-3 from 2017-2018 of $1.04/Wh,[10] but it could be argued that the incentive rate be set closer to $0.90/Wh since the Equity market is just in the first stages of deployment; by contrast, the non-Equity market has been deploying energy storage projects at a wide scale since 2015 or so, giving it a 'head start' on building development experience and reducing soft

[10] *Second Amended Testimony of Southern California Edison Company in Support of its 2018 Energy Storage Procurement and Investment Plan* submitted on March 1, 2018 in A.18-03-002 at pp. 46-47.

costs for its customer base. To encourage synergies with low-income solar programs, the Commission should also explore how an incentive adder could be made available through those programs but funded through SGIP.

In addition, since customer bill savings may be less of an incentive for energy storage deployment for Equity customers (*e.g.*, due to TOU rate exemptions and bill protection measures on tenant loads), CESA recommends exploration of different incentive structures. Grid resiliency adders or bill credits for the use of Equity projects to provide local capacity when sited at eligible customer premises should be explored.

Question 7: Are any modifications to the developer cap in relation to the equity budget warranted? If so, what do you recommend and why?

Yes, CESA recommends removal of the developer cap altogether in the Equity Budget given the lack of activity in this budget category. A bigger priority for these funds is in getting energy storage projects deployed in low-income and DAC markets, over promoting market diversity of energy storage developers at this time. All Equity barriers should be removed for now.

IV. INCENTIVE LEVELS.

Question 1: Have one or more of the above factors changed for a specific SGIP technology such that a modification to the incentive level for that technology is warranted?

Question 2: Is a change in incentive levels prudent for some other reason?

Yes, there is no longer a healthy and steady demand for SGIP storage incentives, and a change in incentive levels is warranted. Since it can be difficult to determine the right incentive amount to catalyze program participation while not over-incentivizing deployment beyond what is needed in the interest of the ratepayer, CESA recommends that the Commission consider a ratchet-up mechanism to the incentive rate in case the current step-down mechanism causes the incentive rate to step-down prematurely with respect to actual capital costs of energy storage systems in the market. Certain thresholds would need to be defined and met to trigger a step-up in incentive rates. The Renewable Market Adjusting Tariff ("ReMAT"), which established bimonthly program periods where prices increased by set $/MWh levels if subscription for a defined period is less than 20% of the available allocation for that product type, may serve as an example to adapt as a model. This serves to help drive deployment if offered prices are not sufficient. In a similar way, the Commission could establish an incentive rate step-up (*e.g.*, $0.15/Wh) if, after a certain amount of time (*e.g.*, 120 days), a certain percentage of available funding in a step (*e.g.*, 20%) is not claimed. Each of the elements (step-up amount, time period, percentage threshold) would need to be set reasonably avoid creating any perverse incentives whereby participants may delay applying for incentives in a timely manner. This may be addressed with the amount of time established for each subscription period.

An additional area for program modification to the incentive structure is around the incentive rate step-down based on project size. Currently, the incentive rate has a percentage discount for incremental project capacity beyond 1 MW and another percentage discount for incremental project capacity beyond 2 MW, up to a 3 MW project size cap that is eligible for SGIP incentives. However, storage capital and soft costs do not decline as the incentive rate step-down structure by project size suggests, which are driven by MW of storage and inverter sizing. CESA thus recommends that the incentive rate percentage discount be removed or revised upwards. Moreover, up to 3 MW of the project size is eligible for SGIP incentives, with costs for any capacity beyond that cap not eligible. For similar reasons, this cap does not appear as needed, especially as project sizing is already baked into other rules. For example, the SGIP Handbook limits project size to customer load, and in cases of solar-paired-storage projects, the storage size is limited to the net energy metering ("NEM") generator to be NEM-eligible and incentivizes to limit project sizing are incorporated into interconnection fast-tracking and cost-allocation rules. Overall, concerns about one project taking all the funds may be less of a concern today given the stagnancy of incentive claims and the sufficiency of funds if the full SB 700 authorization is approved.

V. INCENTIVE STEP-DOWN STRUCTURE.

Question 1: Should the Commission adopt additional steps in the storage or generation budgets?

Question 2: Should the Commission continue stepping down storage incentive levels by $0.05 and generation incentive levels by $0.10?

Yes, CESA recommends the adoption of additional steps in the storage budget. The step mechanism was adopted to avoid a stampede for funds by making funds available on a rolling basis and by having incentive rates set based on market participation levels. As such, a step mechanism in general represents a good framework for SGIP. How those funds should be distributed across the steps warrants further investigation and discussion. However, the current $0.05/Wh step-down can be steep and may lead to the incentive rate dropping precipitously below energy storage cost declines, such that SGIP may see a stall in market activity in the future again. Instead, in the later steps, the Commission should explore lower incentive rate step-downs in the later steps (*e.g.*, \$0.02/Wh or \$0.03/Wh) to mirror how energy storage costs may plateau over time and to ensure the incentive rate does not drop to \$0.00/Wh or some insignificant number.

VI. ADMINISTRATIVE BUDGET.

Question 1: How should the Commission address the large existing balances in PG&E and SCE's administrative budgets?

Question 2: Should the Commission authorize the PAs to shift funding from incentive to administrative budgets via advice letter?

This surplus administrative budget could potentially be leveraged for valuable surveys or studies (*e.g.*, to identify barriers to SGIP participation stagnation) or be reserved for a dedicated ME&O administrator for the Equity Budget. The Commission should also consider directing PG&E and SCE to submit a plan using their administrative budgets to dramatically improve the processing speed of SGIP applications, with consideration of how to help speed the processes for the other PAs as well. As mentioned above, SGIP administration has been slow. In addition, the surplus administrative budget could be re-allocated to the incentive budget if no use of the funds is identified in order to support the further deployment of energy storage projects. Finally, shifting funds to other PAs may be prudent where the number of applications is very high in some areas.

VII. RESILIENCY.

Question 1: What specific resiliency benefits, if any, can BTM storage devices provide to customers and/or communities in the event of a wildfire, wildfire-related de-energization event, or other adverse event?

BTM storage devices can provide varying levels and forms of resiliency services across different customer classes, including being aggregated into microgrids that provide essential or backup power. Standalone and solar-plus-storage systems offer customers a viable means for customers to manage, at a minimum, critical/priority loads during many de-energization events (*e.g.*, heating, cooling, refrigeration, lighting, outlets for phone charging).

Question 1.i: Describe the resiliency need the storage device can address, including the anticipated duration of the need.

There are different types of resiliency needs that customers can face. Typical outages can vary from 0.5 to 4 hours,[11] with certain areas and customer groups facing higher levels of outages.[12] Public Safety Power Shutoffs ("PSPS"), meanwhile, can typically de-energize lines between 24 to 48 hours but customers have been advised to prepare for outages that last longer than 48 hours.[13] Storage devices should be able to provide back-up services to critical loads during a typical outage. However, it may be less likely to be able to meet an extended PSPS without on-site generation and possibly without longer-duration storage solutions. Different levels of service may be considered in providing resiliency service could be met during a PSPS even if some non-critical loads are not served.

<u>Question 1.ii</u>: Describe the resiliency benefit the storage device can provide, including the duration of the benefit.

The duration of the resiliency benefit will depend on the type of storage device that is installed in the customers home, whether the storage device is paired with onsite generation, and whether full or critical loads are wired for the storage device to provide resiliency. By targeting critical loads and pairing onsite generation with commercially-available batteries, a typical residential storage device has the ability to ride-through a multi-hour outage or multi-day de-energization event (see Appendix B). Some battery technologies or configurations, including flow or zinc-air solutions with 4- to 10-hour energy durations can provide longer load shifting and resiliency capabilities. However, there are some limitations or considerations for the resiliency benefits of storage. Not all customers may be able afford the upgrades necessary to enable their storage device to serve critical loads where installation would require the re-wiring of breaker panels and installation of specialized switchgear. Furthermore, standalone storage and solar-paired-storage devices have the capability to ride through PSPS events that mitigate the impacts of a wildfire prevention measure but actual performance in an event will depend on various factors (*e.g.*, solar insolation).

<u>Question 1.iii</u>: Address who would benefit from the resiliency service.

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[11] US Energy Information Administration. *Average Frequency and Duration of Electric Distribution Outages Vary By States*: https://www.eia.gov/todayinenergy/detail.php?id=35652

[12] For example, SJV pilot community customers average 1.25-hour outages and PG&E territory-wide outages average 3.5 hours, while certain communities such as Alpaugh experience much more frequent outages as compared to the customer average. See *Reliability Performance Pilot Communities* presentation by PG&E at the San Joaquin Valley Pilot Reliability Workshop on May 7, 2019.

[13] Robust actual data is lacking, but in October 2018, PG&E called a PSPS in Calistoga and adjacent communities, affecting 60,000 customers. Although power was restored for the majority of customers within 1-2 days, there were some customers that took up to 3 days. See PG&E's *Public Safety Power Shutoff, Calistoga* presentation on November 7, 2018 at p. 8. See also PG&E's PSPS FAQ page here.

In general, when storage is sited at a specific customer's facility or home, customers directly benefit from the resiliency service, but there may also be broader societal benefits of reducing congestion on roads to reach community centers or shelters (*i.e.*, mitigating crisis conditions) and avoiding local pollutants and GHG emissions from customers buying backup diesel/gas generators instead, which, individually, can contribute approximately 20 pounds of CO_2 per hour of usage per home and 6.6 times more of GHG emissions than electricity generated by the grid (Appendix B). Storage sited at community centers and public-sector customer facilities provides not only onsite customer resiliency but also provides indirect benefits to the broader community from being able to continue its critical and public services. To that end, coordination with R.18-12-005 is needed, which is focused on defining and identifying public safety partners, water utilities, communication providers, and vulnerable populations in high-fire risk areas.[14]

<u>Question 1.iv</u>: Address whether the on-site generation device would need to be part of a microgrid or be connected to a storage device to provide the resiliency benefit.

Whether onsite generation is needed likely depends on the resiliency use case and storage technology. To provide resiliency across a long period of time or to service more on-site load, an on-site generation device or a specialized long-duration storage technology may be needed. In other cases, a standalone storage device may be sufficient for shorter-duration resiliency needs and/or to instantaneously power an entire microgrid to allow for switching and islanding. Developers should be granted flexibility to determine the appropriate configuration of the resilient resource that allows them to meet customer needs as well as to pursue various (stacked) use cases.

<u>Question 1.v</u>: Address whether or not the use of storage to provide resiliency services during de-energization events introduces public safety risks.

A number of safety standards have been developed by standards development organizations ("SDOs") to mitigate and guard against fire and other safety-related risks of storage devices. UL, IEEE, and NFPA have developed relevant national standards, while the California Building Standards Commission and authorities having jurisdiction ("AHJs") have developed location-specific and state-specific codes and permitting requirements to enhance safety of energy storage systems. Both preventative (*e.g.*, to control thermal runaway risks in the first place) and response-related (*e.g.*, fire

[14] *Proposed Decision Adopting De-Energization (Public Safety Power Shut-Off) Guidelines (Phase 1 Guidelines)* filed on April 26, 2019 at pp. 73 and 78.

suppression, notification, fire responder processes) standards have been developed by these bodies. CESA lists the relevant standards for the Commission in Appendix C. The effective application of these standards should address many of the concerns related to energy storage fire risks, including whether they could be a source of wildfire starts.

In many ways, CESA believes that the use of storage should be weighed against alternative resiliency devices when considering public safety risks, including fire safety, GHG, and criteria pollutant issues. For example, resiliency discussions should consider a 'counter-factual' case should storage solutions not be deployed. In the case of portable generators, which may have their own respective codes and standards, such counter-factual solutions may otherwise present an alternative source of ignition for a wildfire, especially given their mobile characteristics and/or the potential for customers, in a rush to mitigate increasing outage and PSPS risks, to potentially incorrectly install or store these generators, further increasing the risk of initiating or exacerbating a wildfire.[15] The Occupational Safety and Health Administration ("OSHA") identifies the risks of the use of portable generators including fires and electrocution.[16] In contrast, SGIP-funded energy storage systems are required to have a 'physical permanence' attribute[17] and are required to be safely installed by licensed contractors up to codes and standards.

Beyond an obvious high-fire risk, there is also a public health risk present from improper use of mobile generators, which emit carbon monoxide, an odorless, colorless, and poisonous gas. Reports by Consumer Product Safety Commission ("CPSC") indicate that more than 150 people die every year in the United States from unintentional exposure to carbon monoxide gas from portable generators and other fuel-burning products. Relating to power outages, in 2005, 94 people died from generator related carbon monoxide poisoning, where 50% of those deaths were known to have occurred from power outages due to severe weather.[18] In addition, the prospect of a mass reliance on mobile generators during a PSPS event has the potential of creating upticks in GHG emissions and

[15] For example, they may be unsafely installed in an enclosed area, close to the structure of the house, near dry vegetation, in a wet area, using incorrect extension cords and/or in a way that overloads cords.

[16] OSHA Fact Sheet: Using Portable Generators Safely: https://www.osha.gov/OshDoc/data_Hurricane_Facts/portable_generator_safety.html

[17] 2017 SGIP Handbook at p. 38.

[18] US Consumer Product Safety Commission Carbon Monoxide Questions and Answers: https://www.cpsc.gov/Safety-Education/Safety-Education-Centers/Carbon-Monoxide-Information-Center/Carbon-Monoxide-Questions-and-Answers

local pollutants. An ability to offset such upticks through the deployment of SGIP systems will comport with SGIP goals.

Question 3: Should the Commission seek to promote SGIP projects that provide resiliency benefits to customers and/or communities facing risks of a wildfire, wildfire-related de-energization events, or other adverse event? If so, how?

Yes, CESA believes that SGIP projects can be directed in smart ways as grid and/or policy needs arise, similar to how SGIP has spurred deployment in critical need areas (*e.g.*, lottery priority for projects in West LA Basin to support Aliso Canyon reliability issues) or aims to incentivize specific policy objectives (*e.g.*, in-state economic development via the California Supplier Adder). Resiliency against wildfire-related de-energization events and other weather-related outages presents an opportunity to avoid having customers experience frequent and significant outages and would ensure compliance with the statute to ensure that SGIP projects support onsite reliability.[19]

Question 4: Should the Commission adopt a dedicated incentive aimed at promoting SGIP technologies with resiliency benefits?

Question 5: More specifically, should the Commission adopt a "resiliency adder" to existing incentives for storage and/or generation projects that provide resiliency benefits?

Yes, a resiliency adder is more likely to spur more immediate deployment of SGIP systems for resiliency purposes, more so than a dedicated incentive or a carve-out. Although a dedicated incentive or carve-out may ensure funds are set aside for the intended purpose, there is a risk that the reserved funds do not get used similar to the current Equity Budget unless a higher incentive rate is available to send a market signal on the urgency of such projects. Furthermore, the Commission should also recognize that resiliency applications may involve additional costs that warrant the additional incentive payments since these projects may require different inverters and switchgear and/or reconfiguration of the service panel to serve partial or essential load.

Question 5.i: At what level should an adder be set (e.g., a certain percentage above existing incentive levels)?

[19] See Public Utilities Code Section 379.6(l)(7) as modified by SB 700: "The ability to improve onsite electricity reliability as compared to onsite electricity reliability before the self-generation incentive program technology was placed in service."

Rather than conducting extensive studies on the appropriate value of resiliency at this time, CESA recommends that the resiliency adder be minimally set at least at 20% of the applicable incentive rate, as an initial setting. This adder level would be equivalent to the California Supplier Adder and would minimally equate the resiliency value to the value of in-state economic development from SGIP projects. This is a crude and likely undervalued approximation of the resiliency value, but CESA believes that expediency to deploy SGIP projects for resiliency is needed at this time more so than more accurately determining the appropriate incentive adder level. Rather, the near term may be better spent on developing the eligibility and demonstration protocols to ensure resilient SGIP systems are efficiently deployed and operated during an outage or PSPS event. The adder level could be re-assessed depending on incentive claim levels for the adder and/or depending on the measured performance of SGIP systems in response to an outage or PSPS event. Ratchet-up approaches (*e.g.*, to a 40% adder, could also be enacted if resiliency deployment uptakes are slow.

<u>Question 5.ii</u>: What are appropriate project eligibility criteria to receive the adder?

This Ruling lays out reasonable customer types to target, which should leverage carefully developed R.18-12-005 definitions and frameworks to ensure critical public services can continue to be provided while vulnerable populations are able to subsist during a PSPS event without harm to their health and well-being. The adder should be layered on top of the applicable incentive rate – *e.g.*, medical baseline customers should be eligible for adder on top of the Equity incentive rate. Even though certain customers may be targeted and prioritized, such as with outreach, all customers subject to PSPS events should be eligible for the adder given the SB 700 guidance on onsite reliability and the GHG impacts of gas or diesel alternatives.

<u>Question 5.iii</u>: Should projects receiving the adder be required to demonstrate or attest that they will provide resiliency benefits?

Yes, projects should demonstrate or attest to the ability to provide resiliency benefits. This can be accomplished through the application process to verify the configuration of the SGIP project to provide backup as well as a signed attestation on the SGIP applicants' use of the storage device for safe/reliable backup power.

<u>Question 5.iv</u>: What conditions should the Commission impose to ensure that resiliency services provided during de-energization events do not undermine the intended benefits of the de-energization?

Since resiliency applications require less frequent cycling and the need to have sufficient state of charge in advance of an outage or PSPS event, exemptions or removal of select provisions, such as cycling and roundtrip efficiency requirements, should be explored to ensure effective delivery of the resiliency service and to enable the participation of lower-cost long-duration storage technologies. Rules against the use of backup power (*e.g.*, residential attestation) may also need to be revised for eligible resiliency customers. Finally, if backup power is needed frequently due to increased frequency of outages or PSPS events, the Commission may also need to consider whether and/or how to assess these systems for GHG benefits, where distribution grid needs are not always aligned with marginal GHG emissions on the system grid.

Question 6: Should the Commission modify the existing SGIP incentive structure to facilitate storage projects with a discharge duration exceeding two hours?

Rather than a carve-out for long-duration storage technologies, CESA recommends that incentive rates for duration of energy storage projects be revised upwards to recognize the costs of additional duration beyond two hours as well as the grid benefits of additional duration designed to address solar integration and/or provide load shifting. As highlighted in Appendix A, almost all of residential projects and more than half of non-residential projects are pairing with solar to provide load shifting. Furthermore, the length of peak periods adopted by the utilities span four to five hours, while energy storage systems qualify for Resource Adequacy ("RA") based on four hours of equivalent capacity. Longer-duration storage systems are also needed to provide resiliency in the face of outages and PSPS events, may play a role to address RA needs, such as where more than 8 hours of local capacity deficiencies have been identified,[20] and play a role in a deep decarbonization future.[21] As a result, CESA recommends the following modifications to incentive rates by duration:

Storage Duration	Proposed Incentive Rate (% of Base)
0-4 hours	100%

[20] For example, the Moorpark sub-area was studied and found to have a large capacity need as well as an eight-hour energy need. Although recent contracts were announced regarding the use of portfolios of four-hour energy storage systems, this type of portfolio approach may not always be possible, where longer-duration storage solutions would then be needed.

[21] Long-duration storage was identified as being needed in the 28 MMT by 2030 scenarios in the IRP. Bulk pumped hydro storage served as a proxy variable for such resources, where more than 1,000 MW was selected as part of the optimal resource mix.

4-6 hours	75%
6-8 hours	50%
8-10 hours	25%

With the proposed rate step-down above, the Commission sends a more effective market signal highlighting the importance of and the need to transform the market for longer-duration storage, including to spur the market for thermal energy storage ("TES") systems. Given the sufficiency of funds, especially if the Commission approves the full SB 700 authorization, the previous concerns about a few projects claiming a disproportionate share of funds are less significant. To reach SB 100 goals and support resiliency, a diverse portfolio of storage technologies and durations is needed.

VIII. SAN JOAQUIN VALLEY.

Question 1: Should the Commission adopt changes to the SGIP program for the SJV pilot communities identified in D.18-12-015?

CESA supports the allocation of SGIP funding for underserved pilot communities in the San Joaquin Valley ("SJV"). In evaluating the pilot with respect to the program goals, CESA recommends that the Commission consider the broader context of introducing storage systems to communities that still rely on wood burning appliances.[22] In this context, evaluating the environmental benefits should account for the counterfactual baseline technology that is being replaced by energy storage systems, unlike other typical SGIP customers who may already have electrical appliances. By displacing wood-burning appliance, there may be an added health and resiliency benefit as well. The totality of these benefits should be evaluated.

Question 1.i: If yes, should the Commission adopt an SJV set-aside within the SGIP equity budget at the levels suggested in D.18-12-015 and the SJV ACR ($10 million)?

CESA supports the $10 million set-aside as well as the proposed division of this set-aside budget between SJV residential and non-residential projects.[23] Since many of these community members rely heavily on wood-burning or propane use and have expressed concern about a high frequency of electric power outages, these storage projects will allow the Commission to assess how

[22] *Assigned Commissioner's Ruling Proposing Phase II Pilot Projects in 12 communities in the San Joaquin Valley and Noticing All-Party Meeting* filed on October 3, 2018 in R.15-03-010 at p. 7.

[23] *Ibid* at p. 42 (Table 8 *Proposed SGIP SJV Systems and Estimated Costs*)

pilot participants perceive energy storage systems and broader electrification efforts. After gaining a higher sense of familiarity and potentially also receiving resiliency benefits from storage systems, SJV customers may experience reduced skepticism to a highly electrified future.

IX. GRID SUPPORT.

Question 1: What are the grid benefits, if any, of onsite solar paired with a storage system that is operated to maximize solar self-consumption?

Maximizing solar self-consumption limits the amount of grid-supplied energy needed to serve the onsite load. Thus, depending on the rate schedule and the load profile of the onsite customer, a solar self-consumption maximization strategy could offset the need for system power during peak periods in the 4pm to 9pm range, where marginal GHG emissions and marginal costs tend to be highest. In addition, solar self-consumption reduces overgeneration and renewables integration needs, thus reducing the need for additional upgrades and costs to accommodate additional solar exports. Depending on the configuration, a solar self-consumption maximization strategy could provide resiliency benefits that support the ride-through of de-energization events.

Question 2: What are the grid benefits, if any, if non-residential SGIP customers are on a "storage" rate that reduces non-coincident demand changes?

CESA supports rate design principles that align with cost causation and balance the need to support broader distributed energy resource ("DER") policy goals. Rate designs that provide greater certainty in the periods in which demand charges are assessed and align with peak period cost drivers better incent energy storage systems to operate for grid and GHG benefit. The Option S and A-1-STORE rates from PG&E and Option E and TOU-GS-1 Option ES rates from SCE provide such economic signals that encourage charging at times of low or negative energy demand and discharging when demand is highest to arbitrage TOU rates, respond to critical peak pricing ("CPP") events, and/or mitigate demand charges. Retail rate misalignment with grid conditions, as well as other economic factors related to timing of operations, certainly can drive energy storage operations that may not necessarily align with marginal GHG emissions on the grid,[24] so by adjusting aligning rates with grid conditions (*e.g.*, shifting TOU periods to the later evening hours) and by assessing and recovering demand charges during daily peak period (Option S) or only during partial peak and peak

[24] *SGIP GHG Signal Working Group Final Report* filed in September 13, 2018 in R.12-11-005 at p. 28.

periods (A-1-STORE), energy storage resources will be incentivized to operate in a grid-benefitting manner.[25] Similarly, SCE's TOU-GS-1 Option ES rate accomplishes the same peak-reducing behavior by aligning CPP events with the new TOU peak periods. Of course, not all grid costs are driven by the peak period, but the SGIP GHG report has shown that aligning rates with new TOU peak periods aligns often with marginal GHG emissions today.

<u>Question 3</u>: Do you agree that the Commission should require new residential SGIP customers, who do not receive a GHG signal, to enroll in an existing DR program offered by their utility or in the DRAM as a way to achieve grid benefits and/or GHG reductions from such systems?

CESA does not support a requirement that new residential SGIP customers enroll in some type of a grid-support program like demand response ("DR"), though such programs could be presented as viable deemed-compliant pathways to meet SGIP's grid-support goals. First, residential DR programs are not explicitly designed to provide GHG reductions or to encourage frequent cycling and dispatch, so Commission expectations for such a requirement may not come to fruition. Second, utilities offer a limited range of DR programs to residential customers, with the majority of DR programs targeted at commercial and industrial customers. The few residential DR programs offered by the IOUs are not available to and/or good fits for energy storage systems. The Capacity Bidding Program ("CBP") may be opened to residential customers in the near future but currently only allow enrollment from customers who take service under a commercial or agricultural rate. The DR Auction Mechanism ("DRAM") may be a good fit for residential SGIP customers but it faces uncertainty from being a pilot that is currently under review for its long-term viability and goals. As a reverse auction, DRAM is no guarantee that residential SGIP customers could even participate if their bids are not competitive against non-residential DR bids, especially if the 20% residential carve-out is removed. To summarize, a requirement to enroll in a DR program is not guaranteed and is unviable as a compliance requirement but could be offered as a compliance option.

<u>Question 4</u>: Explain how new non-residential SGIP customers can provide flexible resource adequacy that is recognized by CAISO. Should this be required for new non-residential SGIP customers?

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[25] If a customer's non-coincident peak coincides with the local peak, CESA notes that there is modest value to supporting local distribution system needs by reducing load when the local system peaks.

Non-residential SGIP customers have the capability to provide Flexible RA and have demonstrated such abilities through the procurement of energy storage systems in utility solicitations to meet local capacity needs where Local RA and Flexible RA attributes are often procured together. However, the challenge with making Flexible RA provision a requirement is the insignificant price premium paid for such services[26] and the need to have Flexible RA services paid for through contracts, which requires a load-serving entity ("LSE") buyer and solicitation. Flexible RA is also measured through participation in CAISO markets in accordance with must-offer obligations, effectively requiring direct participation in CAISO markets. This may be complex, daunting, and difficult for some parties, in addition to not being worthwhile. Thus, Flexible RA as a requirement for non-residential SGIP customers is not viable as a grid-support pathway but could be offered as a compliance option if successful in securing contracts.

Question 5: How can we ensure that municipal utility customers who receive SGIP incentives for battery installation provide grid support?

Many municipal utilities have flat or tiered residential rate structures that minimally encourage storage operations to provide grid/GHG benefits and may have few DR programs that direct storage dispatch in response to DR events. Since the Commission has no authority over municipal utilities to direct the development of grid-benefiting or GHG-aligned rates or programs, CESA instead recommends that the Commission pursue a suite of approaches, including recommending to municipal utility customers who deploy SGIP storage systems to only charge from onsite solar as a deemed compliance pathway to meet the GHG emissions goal, to go on TOU rates, or to attempt to operate systems in line with marginal emissions signals, if provided. As new rates or DR programs are developed, the Commission can assess whether to offer them as alternative compliance options.

Question 6: Do you agree that the Commission should consider other ways of promoting SGIP customer participation in DR programs, CAISO energy and ancillary service markets and/or the regional EIM?

Promoting and encouraging SGIP customers to participate in grid-service programs and/or markets is a worthy endeavor, though such "requirements" should be presented as options, not narrow prescriptions. Fundamentally, SGIP continues to be largely a technology deployment, and the level of services provided by SGIP systems and contracts will differ from those of full capacity contracts.

[26] The Annual RA Report does not report the average Flexible RA prices but prices have been anecdotally reported at less than $1/kW-month – much less than the $2/kW-month to $10/kW-month range for Local RA prices, which varies based on location and month.

Before promoting pathways to boost participation in DR programs, however, the Commission should recognize that there are key policy and market-entry barriers that must first be resolved to make these pathways viable even as options. These include dual DR participation prohibitions, incrementality definitions, and a range of wholesale market participation barriers (*e.g.*, metering, settlement) – many of which were highlighted in the Multiple-Use Applications ("MUA") Report.[27] These issues are beyond the scope of this proceeding and thus CESA recommends against prescriptive grid-support pathways for SGIP systems that may not be viable today.

X. **<u>THERMAL ENERGY STORAGE</u>.**

<u>Question 1</u>: What program modifications, if any, should the Commission adopt to increase SGIP participation by thermal and/or mechanical energy storage technologies?

CESA agrees that the limited SGIP incentive funds claimed by TES projects represent a challenge of the program that warrants further attention and consideration of solutions, in order to transform the market for a diverse portfolio of technologies that may each have useful applications. The discontinuance of Permanent Load Shifting ("PLS") programs in the state, which was critical for incentivizing TES operations and deployment but found to be unnecessary with SGIP eligibility of TES, is an important reason for fixing SGIP for TES.

CESA understands there are three main challenges to TES participation in SGIP. First, the current measurement and verification ("M&V") methodologies in the SGIP Handbook can diminish the rated kW and kWh capacity of TES systems, leading to potential 'haircuts' in the incentives that can be claimed. There are currently only three buckets for the rating criteria,[28] and these M&V options may be inadequate for the array of TES technologies, which are diverse and are dynamic in terms of the kW and kWh of storage that a TES can provide. In particular, there is no application methodology for large TES systems, which, as a result, are unable to apply for SGIP incentives. The program has been designed to measure electricity going into and coming out of TES systems, but some TES technologies are unique in that the output is actually thermal energy and where equivalent kWh amounts change based on the ambient temperature. An alternative methodology of determining the

[27] See report: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M233/K836/233836260.PDF

[28] See 2017 SGIP Handbook at p. 42, 43 and Appendix D. The current method estimates electric grid impact of TES systems based on a 10-day average baseline for a given hour of the day, whereby the value of the TES system is determined as the difference between the baseline and the measured energy use for that hour.

electric grid impact of TES systems is needed to accurately reflect the capacity and energy rating of TES systems by accounting for weather-sensitive baselines and capabilities, with one such data-driven and measured approach presented in Appendix D. However, TES systems today have not participated in SGIP due to the insufficient level of eligible incentives as calculated using current M&V methodologies

Second, TES systems are typically used for longer durations (*e.g.*, 4- to 8-hour discharge cycles during the day) but the current incentive rate step-down for incremental energy storage durations beyond two hours creates an additional 'discount' in the incentives that TES systems are eligible for. By adopting CESA's modifications to the incentive rate step-down structure as proposed in our response to Question 6 in the Resiliency section, the Commission sends an appropriate market signal highlighting the importance of long-duration storage like TES.

Finally, recent rate changes also present additional barrier to TES. According to CESA member input, refrigeration can be a large component of a customer's electric loads, and so refrigeration-focused cost savings through TES can be affected by evolving rates, adding uncertainty to a prospective TES customers. While CESA understands the nature and role of rate design changes at the Commission and recognizes that rates are outside the scope of this proceeding, CESA raises this as one explanation for the lack of TES deployment in SGIP.

<u>Question 2</u>: Should the Commission modify SGIP rules to increase the participation of electric heat pump water heaters?

CESA recommends the Commission modify SGIP rules, including around eligibility, to increase the participation of grid-interactive electric heat pump water heaters ("EHPWHs") and electric resistance water heaters ("ERHWs") in residential and non-residential buildings. CESA presented our analysis for why electric HPWHs qualify as an eligible energy storage technology, so long as the energy storage unit was "new",[29] which was accepted by the Commission in a pending decision on May 30, 2019.[30] Increasing participation of new water heaters that can charge during midday solar hours and be utilized during high-emission peak hours would be consistent with the state's efforts to reduce GHG emissions associated with building loads. We encourage the

[29] *Opening Brief of the California Energy Storage Alliance* submitted on October 5, 2018 in A.18-02-016, *et al* at pp. 13-14. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M237/K433/237433470.PDF

[30] *Proposed Decision Implementing the AB 2868 Energy Storage Program and Investment Framework and Approving AB 2868 Applications with Modification* filed on February 26, 2019 in A.18-02-016, *et al* at p. 36. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M269/K191/269191162.PDF

Commission to also consider whether or not retrofitting ‘dumb’ electric water heaters with grid-interactive controls should also be considered SGIP-eligible TES. Relatively inexpensive controllers have demonstrated the ability to convert electric water heaters into grid-supporting energy storage assets.[31] Furthermore, many electric water heaters are located in low- and moderate-income homes whose owners or renters may be unable to afford full DER upgrades, so support for grid-interactive controllers would present a cost-effective method to reach Equity customers. Importantly, these controllers can be installed off-tank, so when ERWHs are eventually replaced with HPWHs, the controller can still be used to effectively manage EHPWHs as well

XI. CONCLUSION.

CESA appreciates the opportunity to submit these comments to the Ruling and looks forward to working with the Commission and stakeholders in this proceeding.

Respectfully submitted,

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CALIFORNIA ENERGY STORAGE ALLIANCE

Date: May 30, 2019

[31] *The Hidden Battery: Opportunities in Electric Water Heating* prepared by The Brattle Group in January 2016. https://brattlefiles.blob.core.windows.net/files/7167_the_hidden_battery_-_opportunities_in_electric_water_heating.pdf

Appendix A:
SGIP Program Statistics

Table 1
Percent of Electrochemical, Thermal, or Mechanical Storage SGIP-funded Systems Paired with Renewables as of 5/20/2019. Table excludes equity projects, cancelled, waitlisted, payment recalled, rejected, or suspended status.

Year	Step 1	Step 2	Step 3	Step 4	Step 5	Average
2017	93.9%	86.8%				89.0%
2018		96.1%	97.0%	99.3%	97.8%	97.7%
2019		88.5%	82.9%	98.4%		95.6%
TOTAL	**93.9%**	**89.3%**	**96.2%**	**99.0%**	**97.8%**	**94.6%**

Table 2
Percent of Small Residential Electrochemical, Thermal, or Mechanical Storage SGIP-funded Systems Paired with Renewables as of 5/20/2019. Table excludes equity projects, cancelled, waitlisted, payment recalled, rejected, or suspended status.

Year	Step 1	Step 2	Step 3	Step 4	Step 5	Average
2017	95.3%	94.5%				94.7%
2018		98.7%	98.2%	99.3%	97.8%	98.6%
2019			99.1%	98.4%		98.5%
TOTAL	95.3%	95.7%	98.3%	99.0%	97.8%	97.4%

Table 3
Percent of Large-Scale Electrochemical, Thermal, or Mechanical Storage SGIP-funded Systems Paired with Renewables as of 5/20/2019. Table excludes equity projects, cancelled, waitlisted, payment recalled, rejected, or suspended status.

Year	Step 1	Step 2	Step 3	Average
2017	84.6%	55.3%		62.0%
2018		66.7%	52.9%	59.6%
2019		88.5%	49.0%	62.7%
TOTAL	84.6%	58.3%	51.3%	61.6%

Appendix B:

Storage for Resiliency Example and Portable Generator GHG Emissions Calculation

Example Resiliency Calculation:
Average residential customer load and the size storage device

To illustrate, some SGIP-eligible batteries, such as Tesla's Powerwall 2, offer approximately 13.5 kWh of usable energy on a full single charge.[32] The average residential load in California is 557 kWh per month or 18.56 kWh a day.[33] In many cases, a single Powerwall can be paired with a 7.6-kW AC solar system to ensure reliable operation during grid outages.[34] Assuming perfect irradiance and no customer demand from either solar or the battery, it would take about 2.75 hours to charge the battery to its full capacity given a 5-kW maximum continuous charge capacity of real power. Taking into account the average residential load and the total usable energy of the Tesla Powerwall 2, this leaves 5 kWh of load that a Tesla Powerwall 2 would be unable to serve.

For longer-duration resiliency needs, a solution for the unserved average load could be needed depending on several factors. One factor is the amount of critical loads. For example, one way to mitigate the issue of unserved average load is to configure the Tesla Powerwall 2 and home circuitry to only serve critical load during instances of outages or de-energization. Potential end-use loads and devices that could be included as part of the critical load designation include a few 60-W LED light bulbs, an Energy Star refrigerator/freezer, an electric stove, a microwave, a water heater, a plug for cellphone charging, and an HVAC reconfigured to serve only the master bedroom. By targeting critical loads in the above manner there's a higher likelihood that a typical residential storage device would ride-through a multi-hour outage or multi-day de-energization event if paired with solar. Re-configuration, however, may come at a high retrofit cost and may not be feasible for all customers.

Portable Generator GHG Emissions Calculation

- A popular portable generator uses 1 gallon of gasoline to generate 5.6 kWh.[35]
- At a rate of 19.6 lbs of CO2 per gallon of gasoline,[36] this generator creates energy at 3.5 lbs of CO2 per kWh.
- The WECC California Subgrid generates only 0.53 lbs of CO2 per kWh on average.[37]
- This indicates that portable generator usage contributes approximately 6.6 times the CO2 emissions of energy generated by the California grid.

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[32] Tesla Powerwall 2 Datasheet: https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf

[33] *Comparative Analysis of Utility Services & Rates in California*, CPUC Policy & Planning Division at p. 9.

[34] Tesla FAQ page: https://www.tesla.com/en_NZ/support/powerwall/faqs

[35] Generac RS700E Spec Sheet

[36] Carbon Dioxide Emission Coefficients, EIA.gov

[37] eGRID Summary Tables 2016, epa.gov

Appendix C:

List of Applicable Safety Standards Addressing Fire Risks

List of Applicable Safety Standards Addressing Fire Risks

Lithium batteries are governed by UL 1642, where requirements are established to reduce the risk of fire or explosion.[38]

Inverters, converters, controllers and interconnection system equipment for use with DERs are governed by UL 1741, IEEE 1547, and NFPA 70 where these requirements cover among other things rapid shutdown requirements.[39]

Energy storage systems or battery systems that are paired with PV or wind turbines are governed by UL 1973 to evaluate that the asset can safely withstand simulated abuse conditions.[40]

The broader category for stand-alone energy storage, including electrochemical, chemical, mechanical, and thermal devices, are governed by UL 9540, which covers fire detection and suppression, among other things.[41]

For the installation of energy storage systems, the following relevant codes and standards are present:[42]

- Fire and smoke detection, fire suppression, fire and smoke containment (NFPA 1, 12, 15, 101, 850, and 851)
- Mitigation of generation of combustible gases or fluids (NFPA 1, 7, and IEEE 1635)
- Electrical safety, emergency shutoff, working space, electrical connections for BTM storage (NFPA 70 and 70E)
- Electrical safety, emergency shutoff, remote shutdown, working space, electrical connections for IFOM storage (IEEE C2 and NFPA 5000)
- Anchoring and protection from natural disasters (seismic, flood, etc.) and the elements (rain, snow, wind, etc.) are governed by IEC 60529, IEEE 1375, UL 96A, IFC, IFC, and NFPA 70 and 5000.

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[38] UL 1642 Section 1.3: https://standardscatalog.ul.com/standards/en/standard_1642_5

[39] UL 1741 Section 1.6: https://standardscatalog.ul.com/standards/en/standard_1741_2

[40] UL 1973 Section 1.4: https://standardscatalog.ul.com/standards/en/standard_1973_2

[41] *Establishing Safety of Energy Storage – an Overview of UL Safety Standards* at Slide 17.

[42] *Energy Storage System Guide for Compliance with Safety Codes and Standards* report prepared by Pacific Northwest National Laboratory, and Sandia National Laboratories at Section 4.4. https://www.sandia.gov/ess-ssl/publications/SAND2016-5977R.pdf

Appendix D:

Back-of-Envelope Calculation of Storage Needs Based on Solar Forecast

BTM PV Assumptions Used in 2017-2018 IRP Based on CEC 2017 IEPR CAISO Load Modifiers Mid AAEEAAPV Workbook

Behind-the-Meter PV (GWh)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Committed BTM PV													
Active: CEC 2017 IEPR - Mid PV	12,250	14,093	15,762	17,456	19,126	20,744	22,314	23,816	25,240	26,591	27,885	29,177	30,506
AAPV													
Active: CEC 2017 IEPR - Mid-Mid AAPV	-	-	160	461	765	1,068	1,369	1,671	1,973	2,269	2,561	2,848	3,129
Total BTM PV	12,250	14,093	15,922	17,916	19,890	21,812	23,683	25,487	27,213	28,861	30,446	32,025	33,634
Equivalent MW - using shape's capacity factor	7,281	8,377	9,464	10,649	11,823	12,965	14,077	15,149	16,175	17,154	18,097	19,035	19,992

Calculation: Storage Forecasted Need Based on Solar Forecast Through 2030

- The difference total forecasted BTM PV added between 2018 and 2024 is 6,796 MW.
- Based on statistics summarized in Appendix A, conservatively assume that 80% of this forecasted BTM PV will be paired with energy storage, even though the 2017 IEPR forecast seems to suggest otherwise,[43] which leads to 5,436 MW of projected BTM PV that will be paired with solar. Not all storage will be paired with solar, but the potential for resiliency applications and the phase down of the ITC also makes this an attractive pairing.
- Assume a 0.7 storage-to-solar sizing ratio even though actual sizing will vary based on the application,[44] which leads to 3,805 MW of storage deployed to meet forecasted BTM PV.
- Assume a four-hour storage duration due to increased load shifting, resiliency, and potential RA applications, which results in 15,223 MWh (15,223,000,000 Wh). Even assuming a two-hour storage duration to reflect current rules, this results in 7,610 MWh (7,610,000,000 Wh).
- Assume $0.25/Wh for the duration of 2018-2024 to be conservative to demonstrate how much money would be needed to support SGIP storage deployments if costs came down rapidly so that SGIP would not have to provide as much funding support, even though there are certain market segments such as the Equity Budget where higher incentive rates are needed. This leads to $3.8 billion ($1.9 billion) in SGIP funding needed to meet forecasted solar demand growth with two-hour storage.
- The calculated SGIP funding needed is conservative and only looks at meeting forecasted solar growth. There are a number of standalone storage applications that would also need support but are harder to forecast. While there may be some overlap, the storage demand for resiliency will also be high, as recent analysis has highlighted that 1.1 million California buildings are in a very severe hazard zone,[45] with approximately 11 million people live in a high or very high fire-risk area.[46]

[43] See *Final CAISO Load Modifiers Mid Baseline Mid AAEEAAPV CEDU 2018*: https://efiling.energy.ca.gov/GetDocument.aspx?tn=226464&DocumentContentId=57241

[44] Simpkins, *et al*. *Optimal Sizing of a Solar-Plus-Storage System For Utility Bill Savings and Resiliency Benefits*, NREL Conference Paper presented at Seventh Conference on Innovative Smart Grid Technologies (ISGT2016) on September 6-9, 2016 at p. 5. https://www.nrel.gov/docs/fy17osti/66088.pdf

[45] Smith, Doug and Ben Welsh. "A million California buildings face wildfire risk. 'Extraordinary steps' are needed to protect them." LA Times on December 18, 2018. https://www.latimes.com/projects/la-me-california-buildings-in-fire-zones/

[46] Westervelt, Eric. "After Paradise, Living With Fire Means Redefining Resilience." NPR on May 29, 2019. https://www.npr.org/2019/05/29/724407043/after-paradise-living-with-fire-means-redefining-resilience

Sensitivities: Storage Forecasted Need Based on Solar Forecast Through 2030

% Paired Storage	Storage-to-Solar Sizing Ratio	Storage Duration	'Blended' 2018-2024 Incentive Rate	SGIP Funding Needed
80%	0.7	4	$0.25/Wh	$3.8B
80%	0.7	2	$0.25/Wh	$1.9B
60%	0.7	4	$0.25/Wh	$2.8B
60%	0.7	2	$0.25/Wh	$1.4B
60%	0.7	4	$0.15/Wh	$1.7B
60%	0.7	2	$0.15/Wh	$0.8B

Appendix E:

Proposed Modifications to TES Program Design

L-TES Program Design

Preface

CESA and Trane US has been working with the SGIP PAs informally on one potential program design change to the M&V methodology to more accurately establish a baseline for capacity and energy ratings for large TES (L-TES) utilizing a methodology developed by Negawatt Assets, though other dynamic baseline methodologies could be developed and/or identified. Below, CESA provides an attached proposal for the Commission's consideration.

Current Methodology

The current approved methodology for small TES (S-TES) is based on deemed values. The S-TES systems were approved more than a decade ago for the purpose of Title 24 compliance, but CESA notes that monitoring technology has developed significantly since then. The deemed methodology does not give full attribution for the peak attributes of large TES when effectively all other technologies are given credit for what their contribution to peak will be at peak conditions.[47] Importantly, the current method estimates electric grid impact of TES systems based on a 10-day average baseline for a given hour of the day, whereby the value of the TES system is determined as the difference between the baseline and the measured energy use for that hour.[48] This underestimates the energy performance of the L-TES when weather sensitivity is not accounted for.

Proposal Overview

CESA supports the use of a deemed value process for applications where monitoring costs would be prohibitive, but proposes a methodology that makes the upfront incentive payment based on a kW peak calculation and that pays PBI incentives based on modeling, bin analysis, and actual measurement and performance over time to ensure that ratepayer funds are well used and achieve their intended outcomes. A 'baseline' is developed using continuous monitoring and data collection for when the TES system is on and off at different ambient air temperatures.

For capacity rating to calculate upfront incentives, CESA recommends that this be calculated using the methodology developed by UC Davis that measures simulated grid impact at 1-in-10 heat storm conditions. By basing estimates on a "10-day average baseline," the study found that the impact of disconnecting the cooling system from the electric grid were drastically under-estimated by as much as 77% (or 38% to 57% on average) when temperatures outside are very hot and the grid reaches its peak load conditions (*i.e.*, 12 hottest four-hour periods of the year chosen as "event

[47] The deemed tables for ice storage were developed for Title 24 compliance and were based on the peak hour. PLS, batteries, and peakers have their capacity measured based on peak hour.

[48] See 2017 SGIP Handbook at p. 42, 43 and Appendix D.

days," excluding weekends, holidays, and prior event days).[49] However, by using a 1-in-10 measurement of the capacity of the L-TES system, it appropriately captures the full capacity capabilities.

For energy rating to calculate PBI incentives, CESA recommends the use of Negawatt Assets' methodology or some other dynamic baseline calculation methodology. Negawatt Assets' modeling estimates the hour-by-hour impacts of the proposed system at the time of initial application, taking into account hourly temperatures, attendant variable loads, and part-load performance of the specific equipment being installed or offset. This hourly data will then be arranged by temperature bin for the appropriate occupancy state (occupied or unoccupied) in order to arrive at a mean kWh/hour (mean kW at a given bin temp multiplied by percentage of hour running) on and mean kWh off for that bin using a TMY3 file, but extended out from the end of the TMY3 hours to the 1-in-10 hour.

Although the data in the bins are initially populated by the model, more recent real-world data would "bump out" model data over time. This means that both the on and the off baselines would be kept up to date over time. For example, if building occupancy went down, then the assumption is that the cooling load would as well. In this case the "non-discharged" value would go down, as would the attributable kW and kWh per hour. This allows the SGIP program to better fulfill its charge to only pay for actually delivered benefits than does the currently proposed approach.

Proposal Justifications

Such an approach improves upon the current SGIP methodology for L-TES systems because the measurements used are those for the actual equipment in use at the specific site, as opposed to an average of averages as is the case with CBEC. This approach also better complies with the requirements of AB 802 (which mandates use of measurements from existing equipment), follows the approved methodology for Title 24 building code compliance, and is consistent with the precepts underpinning the International Performance Measurement and Verification (IPMVP) Option B (a peer-reviewed and globally-accepted methodology to calculate the impacts of a given project using actual measurements and monitoring). Furthermore, this approach is much easier to independently validate, as any third party can easily measure kW and run time not only at a single site but also at multiple sites. Finally, use of actual measurement allows calibration of the model to actual baseline system performance, reducing the ability for applicants to game system.

This approach has substantial benefits from a GHG monitoring and reporting perspective. Data is collected continuously in 5-minute blocks, which can be aligned with the real-time GHG signal feed that is under consideration, allowing for greater GHG accounting without unreasonable additional burdens. With reported time stamps, this approach also improves the ability to audit installations to ensure GHG compliance.

[49] See *Valuation of Thermal Energy Storage for Utility Grid Operators by the Western Cooling Efficiency Center* at pp. 1-3. https://wcec.ucdavis.edu/wp-content/uploads/2017/11/Thermal-Energy-Storage-Case-Study.pdf

Despite the substantial improvement in accuracy, the administrative burden would appear to be considerably reduced by this approach. During the application process, a model will be presented that conforms to actual pre-installation site monitoring. During monthly reporting, data will be presented in a simple bin analysis format, allowing simple Excel workbook macros to detect any potential math errors. Lastly, the existing Quality Assurance obligations of PAs will be made much easier, faster, and more difficult to dispute. Since the monitoring reporting for each 5-minute block will include a time stamp, kW reading, and ambient air temperature record, PAs would be able to randomly spot-check sites to cross-check data far more easily than they can audit performance data provider (PDP) reports today.

Importantly, the implications of such a dynamic and measurement-based baseline methodology extend beyond SGIP and could serve as an important component to all DER settlement processes. If DERs in general are going to be a fairly valued component of the future grid, the ability to accurately validate a dynamic baseline must be addressed.

PBI Proposal Details

Like IPMVP Option B, CESA proposes that L-TES be measured before and after at the same data collection points and have the difference reported as the impact. The high-level outline of CESA's proposed methodology involves the following steps:

1. Calculate 1-in-10 Peak kW using the UC Davis methodology.
2. Model system kWh as in the Commission's former PLS program.[50]
3. Use site pre-monitoring to calibrate the model.
4. Use the calibrated 8,760 model to populate a number of 1-hour bins.
5. Interpolate between the end of the bin database and the 1-in-10 peak kW-based UC Davis methodology.
6. "Smooth out" the number of hours in the bins to account for noise in the TMY3 file.
7. Set up the post installation data to be continuously collected.
8. Use the incoming measured system on/off data to replace the data set initially populated by the model, and to update the baseline database on a monthly basis thereafter.
9. Report the differential between actual performance during discharge and baseline monthly for the PBI payment period for both kWh and GHG emissions.

At a high level, this methodology establishes a matrix of simulated baselines that account for hourly temperatures, attendant variable loads, and part-load performance, formed into 'bins', that are used to measure against actual sub-metered performance of the L-TES system. For further details, CESA presents Negawatt Assets' step-by-step methodology that should be considered by the Commission as one potential dynamic baseline methodology to determined PBI incentive payments for L-TES systems.

[50] This Commission-authorized program was specifically aimed at L-TES systems. This proposal builds on the PLS methodology by adding duplicable field measurement upfront to calibrate the initial model, with continuous monitoring and data-driven updates to the database.