BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	Rulemaking 20-11-003 (Filed November 19, 2020)

COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE ON THE PHASE 2 PROPOSED DECISION DIRECTING PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY TO TAKE ACTIONS TO PREPARE FOR POTENTIAL EXTREME WEATHER IN THE SUMMERS OF 2022 AND 2023

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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 on the *Phase 2 Proposed Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023* ("PD"), issued by Administrative Law Judge ("ALJ") Sarah R. Thomas on October 29, 2021.

I. <u>INTRODUCTION</u>.

In the Phase 2 PD, the Commission described the drought conditions, wildfires, and extreme heat experienced over the last several years as a "perfect storm of reliability challenges"[1] that requires the Commission to act now. With emergency conditions likely to persist over the next few summers based on summer stack analyses from the California Energy Commission ("CEC") and California Independent System Operator ("CAISO"), the Commission explained that it is exercising its "policy prerogative" to continue procurement between 2,000 MW and 3,000 MW of contingency resources for Summers 2022 and 2023.[2] Some of the reasons cited included the limited procurement experience of some newer load-serving entities ("LSEs"), delays in current

[1] PD at 5.

[2] PD at 11, 13-14, and Ordering Paragraph ("OP") 3.

Integrated Resource Plan ("IRP") procurement, limitations of current outsized interconnection queues, supply chain risks, and labor availability.[3] Similar to the Phase 1 decision, the Commission opted to apply an effective planning reserve margin ("PRM") to have the investor-owned utilities ("IOUs") serve this emergency backstop function and to afford flexibility in the type of resources that could be procured.

CESA acknowledges the difficult position that the Commission and the state face with respect to near-term emergency reliability. CESA recognizes that electrical reliability through storage is critical to the well-being of ratepayers and society and how it is imperative that the "lights stay on" in the face of increasing levels of extreme weather risk. Simultaneously, the Commission is tasked with ensuring that it does not detract from important priorities to maintain the state's trajectory toward long-term decarbonization goals and minimize ratepayer costs through competitive markets and open-market principles and processes.

With this in mind, in reviewing the Phase 2 PD, CESA has mixed positions on the various solutions and strategies pursued. On the one hand, the PD incrementally improves and enhances the ability of distributed energy resources ("DERs"), including behind-the-meter ("BTM") energy storage and bidirectionally-capable vehicle-to-x ("V2X") resources, to participate in existing demand response ("DR") programs and the recently-adopted Emergency Load Reduction Program ("ELRP"). New, innovative pilots and customer groups will also advance our understanding on how to better leverage DERs for system reliability – some of which can be translated into broader, non-pilot, scaled changes and strategies. On the other hand, the adopted DER strategies are not bold and favor those proposed by staff and the IOUs with little or no discussion on other proposals such as those from CESA, thus falling short in some regards in fully unleashing demand-side load reduction and export potential. In CESA's view, the same urgent decisiveness and all-hands-on-deck approach are not being applied consistently to DER solutions, where changes or procurements for DERs are done on a more careful, incremental basis.[4] In one or all of the upcoming DER-focused proceedings,[5] CESA urges expedited action and focus on how to create

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[3] PD at 17-19.

[4] For example, the complete lack of consideration or discussion of an additional Demand Response Auction Mechanism ("DRAM") is disappointing despite several parties call for the use of this existing mechanism to readily bring capacity online.

[5] *See, e.g.*, the 2023-2027 DR Applications to be filed in May 2022, the High DER Future proceeding (R.21-06-017), Rule 21 proceeding (R.17-07-007), or the forthcoming Load Flexibility rulemaking.

or enhance DER programs that can fully deploy and enable export-capable DERs, beyond an emergency-only program, and expand interconnection strategies.

To this same end, CESA supports the clarifications to allow energy storage to not be deliverable for Resource Adequacy ("RA") yet count toward the emergency reliability procurement requirements as established by the effective PRM.[6] This additional flexibility will help energy storage projects to come online earlier and deliver energy in the near term. However, as recently evidenced by the utility-owned storage ("UOS") procurement by Southern California Edison Company ("SCE"),[7] there is a clear need for guardrails and more specificity on the procurement parameters to avoid harmful precedents without coming at the expense of innovation and creativity. As it currently stands, the PD adopts several changes that authorizes the use of an untested and unvetted approach that warrants further review or requires additional safeguard measures as it applies to SCE's UOS project but also to any future or similar UOS projects.

Considering the above, CESA offers the following comments:

- The clarification that non-deliverable energy storage resources are eligible for emergency Summer 2022/2023 procurement should be approved.
- The proposed use of energy storage uses should align with the use case, benefit-cost allocation mechanism, and pathway to commercial operations.
- The guidance for Mid-Term Reliability ("MTR") procurement compliance should be maintained unless otherwise substantiated.
- In lieu of a capacity payment, the ELRP minimum dispatch hours will provide revenue certainty, but they should be aligned across customer groups where reasonable.
- Sub-metering pathways should be approved, which will enable exports and dual participation across multiple programs.
- Utilities should be directed to bilaterally contract for third-party DR resources, including under long-term contracts.

[6] PD at 100.

[7] *See* SCE Advice 4617-E submitted on October 21, 2021. All arguments from the protests and responses in response to Advice 4617-E are not reiterated here, but some key points from those protests and responses are particularly relevant due to the unsubstantiated determinations made in this PD to support Advice 4617-E without important and necessary modifications.

- The Electric Vehicle ("EV") / Vehicle Grid Aggregation ("VGI") Pilot should be adopted, with some technical clarifications and modifications.

II. <u>THE CLARIFICATION THAT NON-DELIVERABLE ENERGY STORAGE RESOURCES ARE ELIGIBLE FOR EMERGENCY SUMMER 2022/2023 PROCUREMENT SHOULD BE APPROVED</u>.

In opening testimony, CESA advocated for the Commission to allow for "proxy RA" procurement as a means to bring incremental energy storage capacity online as soon as possible and create a bridge to these resources eventually being able to secure Full Capacity Deliverability Status ("FCDS") and count toward RA requirements. Especially with procurement being made to an effective PRM and particularly in locations where transmission or distribution grid capacity is available, the allowance of energy-only ("EO") or Partial Capacity Deliverability Status ("PCDS") resources could facilitate the procurement of energy resources for near-term reliability with preferred resources, as conveyed in Decision ("D.") 21-03-056, while positioning these same resources to meet the state's IRP procurement requirements in the mid and long term.

By recognizing that non-deliverable resources can support near-term reliability during the peak and net peak periods, the PD made important clarifications to allow such resources, which may not otherwise qualify in the near term without securing FCDS to meet the Summers 2022 and 2023 procurement targets.[8] CESA requests clarification that IOUs are allowed to enter into long-term contracts for these proxy RA resources. The PD, of course, underscores the preference for RA-eligible resources that have the advantage of being visible in supply plans and participating in CAISO markets, but this flexibility and allowance is welcome. These long-term contracts are critical for providing the financial viability that can get these resources online in 2022/23 to improve grid reliability and provide energy during the peak and net peak periods. Although such non-deliverable resources were presumably already allowed and approved in some recent procurements,[9] CESA nonetheless strongly supports this clarification to provide explicit clarification and guidance. As explained further below in the next sections, CESA underscores the importance and need to maintain a level playing field where such pathways to procurement and

[8] PD at 23.

[9] *See, e.g.*, PG&E Advice 6089-E that submitted energy-only import contracts for approval.

initial deliveries should be comparably and similarly available to not only UOS projects but also third-party-owned storage ("3POS") projects.

III. THE PROPOSED USE OF ENERGY STORAGE RESOURCES SHOULD ALIGN WITH THE USE CASE, BENEFIT-COST ALLOCATION MECHANISM, AND PATHWAY TO COMMERCIAL OPERATIONS.

In addition to affirming the general procurement parameters and resource types, the PD confirmed SCE's proposed cost allocation approach using distribution rates for its UOS procurement as an acceptable alternative to the Cost Allocation Mechanism ("CAM"), as authorized in D.21-02-028, when resources are operating on non-CAISO-controlled grid assets and outside the CAISO markets.[10] By virtue of distribution cost recovery having a mechanism by which costs and benefits to allocate the attributes of the UOS resource, the PD confirmed this proposal without much examination or consideration of the broader repercussions and complexities on this determination's impact on open-access and interconnection queue rules and competitive and discriminatory competitive impacts to other 3POS and generation resources. This is problematic for many reasons, and to remedy this problematic precedent, CESA recommends several modifications.

First, the Commission should disallow the procurement of distribution resources for the purposes of meeting a capacity shortfall during contingency conditions and events. At no time has the focus of this proceeding been to address distribution capacity needs, so for the purpose of addressing the problems and risks identified in this proceeding, procured resources should not only function as supply resources but also be treated like supply resources, from its operations to meet peak and net peak needs but also in its costs and benefits allocation treatment. It is wholly unreasonable for SCE UOS to be deemed a distribution asset when it is convenient to bypass the usual interconnection processes, be exempt from distribution demand rates, and take up available charging and generation capacity on the distribution system. As explained in CESA's protest to Advice 4617-E, even though for all intents and purposes, the UOS will operate just like any other supply-side asset, the UOS resource will avoid recently-adopted Wholesale Distribution Access Tariff ("WDAT") demand charges and, worse, have other WDAT-interconnected resources pay into the distribution revenue requirement from which the similarly-situated UOS project would

[10] PD at 94-95 and 101.

recover costs through. Yet, none of these considerations are included in the PD's determination, which narrowly focuses on the mechanism by which costs and benefits are allocated. As such, due to the insufficient record to make this determination and the lack of deep consideration of the collateral or precedential impacts, CESA recommends that the Commission *not confirm* SCE's proposed cost allocation approach using distribution rates as an acceptable alternative to the CAM.

At minimum, if the Commission deems it appropriate for the SCE UOS case in the forthcoming Resolution on SCE Advice 4617-E, CESA recommends disallowing this pathway for procurement and operations *going forward* since there is no reason to deviate from normal supply resource interconnection processes to meet Summer 2023 needs. That is, there is sufficient, albeit still limited, lead time to meet Summer 2023 incremental capacity needs from the range of 3POS, DR, and other resource types. This disallowance can be established by adopting the following guardrails to add to the list of general procurement parameters for non-deliverable resources:[11]

- Interconnected to the CAISO or distribution grid with either EO or PCDS resources
- Able to respond to CAISO dispatch instructions at all times, including during the peak and net peak periods
- Available to bid into CAISO markets consistent with must-offer obligations

Second, if resources are allowed to seek approval as a distribution asset and through distribution rates, the Commission should modify the PD to require that such projects maintain their status as non-market assets and be used only on an emergency basis when certain defined emergency reliability conditions are triggered. This would ensure consistency with the pathways available to distribution assets with the cost/benefit allocation mechanism sought. After all, the Commission is authorizing the procurement of resources to meet an effective PRM such that these resources are only needed for extreme weather events and conditions. Allowing the projects to qualify for RA is fraught with many issues and would violate Federal Energy Regulatory Commission ("FERC") open-access rules and regulations if allowed to operate on a regular basis like a supply asset during non-market period and bypass the interconnection queue of other supply resources that are following these rules and regulations. Its infrequent operation except on the most extreme days or grid conditions will also mitigate the frequency of distortionary and "invisible" wholesale market price impacts.

[11] *See, e.g.*, LS Power Opening Testimony at 5-7.

Third, CESA adds that the Commission was previously unambiguous in requiring any procurement pursuant to the emergency reliability needs for Summers 2021 and 2022 shall have costs and benefits allocated to all benefiting customers through the CAM. Since the PD already affirms that non-deliverable resources can be eligible pursuant to the proposed Summers 2022 and 2023 procurement orders, and the Commission has already approved non-deliverable capacity via the CAM, CESA sees no need for alternative mechanisms to be adopted, especially when the approach is fraught with some of the aforementioned problems. The Commission already approved energy-only import contracts even through there are no RA capacity benefits to be allocated to all LSEs via the CAM and did not hinge approval on the specification of energy delivery terms, except to affirm that any incremental procurement must merely "cover the gross load peak and net load peak but does not delineate acceptable or unacceptable delivery terms."[12] Within this context, it is unclear why an alternative mechanism to the CAM is needed, except to allow for the IOUs to pursue UOS as distribution assets and bypass the normal processes.

IV. THE GUIDANCE FOR MID-TERM RELIABILITY PROCUREMENT COMPLIANCE SHOULD BE MAINTAINED UNLESS OTHERWISE SUBSTANTIATED.

The PD clarifies that the application requirement for UOS resources "would lead to delays in contract execution" given the urgency to get new resources online.[13] This determination was made hastily and without much substantiation in the PD, reversing a requirement that the Commission adopted only few months ago via D.21-06-035. The full application was put into place to, among other things, ensure that the resources were cost-competitively procured and ensure healthy markets. Specifically, the MTR procurement decision established a much higher standard of review with parameters guided by D.19-11-016, which cites D.19-06-032 and thus requires the IOUs to ensure that procurement pursuant to meeting the MTR procurement requirements to occur without bias toward any ownership model.[14] Without a procedural venue by which some of the cited concerns can be more fully investigated and vetted by the Commission and other stakeholders, UOS projects could be approved without any checks. At minimum, with a

[12] *See* Commission Energy Division Staff Disposition of Pacific Gas and Electric Company ("PG&E") Advice Letter 6089-E on March 18, 2021 at 4.

[13] PD at 101.

[14] *See* D.21-06-035 at Conclusion of Law ("COL") 24 and D.19-11-016 at FOF 27 and OP 8.

full application process in place, the IOU would face the burden of proof in demonstrating adherence to D.19-11-016 and D.19-06-032, even as the resources are able to come online in the near term to support emergency reliability in Summers 2022 and 2023. Clearly, as evidenced by SCE Advice 4617-E, such checks are needed to avoid discriminatory and harmful outcomes.

V. IN LIEU OF A CAPACITY PAYMENT, THE ELRP MINIMUM DISPATCH HOURS WILL PROVIDE REVENUE CERTAINTY, BUT THEY SHOULD BE ALIGNED ACROSS CUSTOMER GROUPS WHERE REASONABLE.

CESA is pleased to see that the Commission has acknowledged the need for revenue certainty in the ELRP by including minimum dispatch hours for some customer groups.[15] Many parties, including CESA, advocated for capacity payments within ELRP in testimony and briefs, highlighting the need for customers to have certainty in the revenue they will be receiving from the program. This revenue certainty is particularly important for customers looking to invest in distributed energy resources such as energy storage. Combined with the increase in the ELRP payment from $1/kWh to $2/kWh,[16] CESA believes that these steps will spur some greater interest to participate in the program in support of the emergency reliability objectives.

As stated in CESA's opening brief, an alternative to a capacity payment is creating a minimum dispatch requirement that includes more dispatch events than we saw in 2020. This PD includes minimum dispatch requirements for Group A.2 (Non-residential Aggregators), Group A.4 (Virtual Power Plant ["VPP"] Aggregators), and Group A.5 (EV/VGI Aggregators). CESA appreciates and supports the Commission providing clear incentives for customers to join these aggregations to provide grid value and insights into how these aggregations can operate going forward, given that meeting California's environmental, reliability, and resiliency goals will need to leverage novel BTM technologies and aggregations going forward. Given that the aggregations in Groups A.2, A.4, and A.5 are newer business models, CESA agrees that it is most prudent to provide revenue certainty to these categories.

However, CESA recommends that the Commission align the minimum dispatch hours across the customer group categories at 30 hours of dispatch per season, in line with what has been proposed for Group A.5. By contrast, the minimum dispatch hours for Groups A.2 and A.4 are set

[15] PD at 32.

[16] PD at 42-43.

at 10 and 20 hours, respectively, without much explanation. CESA sees no reason why these customer groups should be subject to lower minimum dispatch hour requirements since they should be equally capable. For consistency, unless otherwise substantiated, the Commission should establish a uniform requirement, or at least for Group A.3 and A.4 customers and Group B customers that are certainly capable of supporting greater dispatch. We note that Group B customers would also benefit from this capability to help storage developers make the investments necessary in additional export capability, a unique feature not available in other DR programs. If additional capacity is needed, the Commission should also explore how minimum dispatch hours can be increased for select aggregators to encourage greater participation in the single customer categories of Groups A.1, A.3, and A.6.

Aligning the minimum dispatch hours at a higher level is not only intended to provide revenue certainty but also to leverage these resources on a more frequent basis as "RA-like" resources. The limited lead time until Summers 2022 and 2023 suggest that the Commission should not view the ELRP as solely an "insurance policy" but as a resource that can meet the 2,000-3,000 MW procurement targets. Storage-backed, VGI/V2G, and VPP resources are particularly well-positioned and willing to respond on a more frequent basis and could also support forward planning toward these targets if there are higher expectations to perform. There may be no penalties, but storage-backed resources will have every incentive to participate frequently if dispatched to get compensated for these services.

Furthermore, CESA supports expanding dispatch triggers beyond the existing ELRP triggers in order to enable IOUs to meet the minimum dispatch requirements for the groups outlined in the PD but asks the Commission to direct the IOUs, through their Tier 1 Advice Letters, to provide more clarity on what additional conditions will trigger dispatches for these systems. Currently, the PD states that "IOUs may exercise discretion to dispatch […] in response to other forecasted or anticipated grid stress conditions, such as high locational marginal prices […], extreme heat waves, etc., to achieve the Minimum Dispatch Hours."[17] Clarity surrounding which triggers will be used for these events will help aggregators better prepare to dispatch resources.

Although minimum dispatch requirements provide a certain level of revenue certainty for customers, CESA still stands by the enhanced benefits of capacity payments in the ELRP, which

[17] PD at 31-32.

supports more RA-like dispatch that can support capacity needs, not only on an emergency basis for contingency events but also on a frequent everyday basis. With the Commission affirming that non-deliverable and non-RA resources can qualify for the Summers 2022 and 2023 procurement targets, it is unclear why the Commission is hesitant to establish ELRP customer groups that can "do more" and thus provide RA capacity payments, subject to enhanced compensation and at the same time subject to penalties for non-performance. Importantly, to this end, the Commission should double down on its efforts in the RA proceeding. Currently, resources with exporting capabilities do not have qualifying capacity ("QC") values inclusive of their exports. These issues are going to be discussed in the new RA Proceeding (R.21-10-002), so the Commission should affirm that the adoption of changes in the ELRP do not detract from the progress necessary in R.21-10-002 to establish QC values for BTM hybrids and energy storage to participate more actively as RA resources.

VI. SUB-METERING PATHWAYS SHOULD BE APPROVED, WHICH WILL ENABLE EXPORTS AND DUAL PARTICIPATION ACROSS MULTIPLE PROGRAMS.

CESA is strongly supportive of the PD's adoption of sub-metering approaches for the measurement of incremental load reduction ("ILR") for customers participating in Groups A.4 and A.5,[18] which will more easily distinguish storage discharge and exports as ILR. This is an important determination that will also help address any double counting or compensation concerns associated with dual participation of these resources. CESA appreciates that the Commission enables dual participation for ELRP customers with supply-side DR programs and portfolios via the Group B categories, since the ELRP alone will not facilitate the participation of certain customers, such as those adopting more capital-intensive enabling stationary or mobile energy storage technologies.

However, we observe that Groups A.4 and A.5 are prevented from participating if they are already enrolled in a critical peak pricing ("CPP") or real-time pricing ("RTP") tariff. CESA views this prohibition as too restrictive since it would not enable these customers to provide incremental *energy* by being able to export beyond the customer host load, which would be otherwise uncompensated for VPP or VGI customers. With sub-metering and ILR concepts in place, at

[18] PD at 43 and Attachment 2 at 15.

minimum, the ELRP could be modified for these groups to recognize and compensate storage exports via ILR assessments.

VII. UTILITIES SHOULD BE DIRECTED TO BILATERALLY CONTRACT FOR THIRD-PARTY DEMAND RESPONSE RESOURCES, INCLUDING UNDER LONG-TERM CONTRACTS.

CESA supports the Commission directing the IOUs to procure RA from third-party Demand Response Providers ("DRPs") through bilateral contracts. Notably, CESA reads the current language of "the IOUs shall procure RA capacity from eligible third-party DRPs for 2022 and 2023 deliveries"[19] as *requiring* the procurement of some amount of DR as part of this proceeding. The Commission should consider adding a minimum procurement target for third-party DR among the 2,000-3,000 MW procurement authorization to provide more market certainty to DRPs. This will help DRPs plan for adequate amounts of customers and capacity and provide better offers for utilities. CESA is also glad to see the Commission allowing for additional flexibility for DRPs to participate in this procurement by exempting the requirement for DRPs to have gone through the Load Impact Protocol ("LIP"), which can be very time consuming and expensive to complete. Removing the LIP requirement will enable many more DRPs to provide capacity for these urgent Summer 2022 and 2023 needs.

However, CESA offers a few modifications. While bilateral agreements will provide more flexibility, the IOUs should be directed to consider these contracts for uses beyond short term 2022-2023 emergency reliability needs. These DR resources have the potential to help IOUs meet other important goals, including MTR procurement and long-term IRP compliance obligations. IOUs should be authorized to sign longer-term contracts for capacity deliveries beyond 2022 and 2023 to allow for incremental progress towards these larger reliability and clean energy goals. CESA does not see any language in the current PD that would preclude these longer-term contracts, but additional clarification should be added to ensure that the IOUs are aware of this flexibility.

In addition, the PD attached guidance directs the use of Capacity Bidding Program ("CBP") performance and payment structures for these bilateral negotiations. On its face, this appears to represent an extension of the CBP via bilateral contracts, but this should serve as a starting point,

[19] PD at 61.

where some flexibility should be afforded for long-term BTM storage capacity contracts similar to the ones we have seen the IOUs contract for in the past to meet system and local capacity needs.

VIII. THE EV/VGI AGGREGATION PILOT SHOULD BE ADOPTED, WITH SOME TECHNICAL CLARIFICATIONS AND MODIFICATIONS.

CESA strongly supports the PDs adoption of the EV/VGI aggregation pilot in the ELRP, including most aspects of the Staff Proposal such as the flexibility for the participation of both managed charging ("V1G") and bi-directional vehicle-to-grid ("V2G") technologies in these aggregations. CESA also supports the PD's minimum dispatch requirement of 30 hours for these resources, as it will give utilities and aggregators much-needed data about the potential of these resources. Lastly, CESA supports the use of electric vehicle supply equipment ("EVSE") sub-meters to measure ILR as it will provide greater clarity to the contributions made by these resources, which can also provide data to be leveraged as the Commission and other agencies looking to enable EVs to support the state's grid.

Notably, CESA is generally supportive of the Commission recognizing the nascent market for V2G EVSE and allowing for an exemption to the smart inverter requirements in Rule 21. The Commission recently adopted V2G EVSE interconnection pathways via Resolution E-5165 using smart inverter requirements in place for all inverter-based technologies under Rule 21, where V2G EVSEs that are certified to those standards should still interconnect with the same processes and requirements as other DERs, but the exemptions may help in the near term to expand the scope of eligible V2G EVSEs that may not meet the smart inverter requirements at this time.[20] To this point, CESA recommends that the IOUs specify any alternative technical requirements in subsequent advice letters in lieu of meeting the smart inverter requirements and strive to propose cost-effective pathways, as considered for the temporary pathway for V2G AC interconnections. Additionally, the Commission should maintain that the "termination of this interconnection pathway" will not affect previously interconnected EVSEs.[21] Without this affirmation, V2G EVSEs may be disinclined to participate if they will be forced to no longer operate parallel to the grid as a Rule 21 interconnected resource if and/or when the ELRP sunsets. In other words, EVSEs are long-term

[20] There may be a handful of V2G EVSEs that meet the smart inverter requirements, so this would expand the scope.

[21] PD Attachment 2 at 6.

DER assets that should be grandfathered into the terms of their original interconnection if this interconnection pathway is maintained and offered in the ELRP.

Finally, CESA seeks clarification on whether A.5 resources are allowed to net export to the grid, not just discharge to serve BTM host customer loads. Specifically, we refer to guidance that "the VGI aggregator is permitted to virtually aggregate separately metered EVSE with other load and generation (if any) at an electrically contiguous host site to allow export from the EVSE to reduce the host site's load and export from such aggregation up to the sum of the net export allowed by any available Rule 21 permits of the EVSE site and the host site."[22] Further, by stating that the PD adopts the Staff Proposal, CESA interprets the PD as affirming that the "virtual load aggregation of all stand-alone EVSEs and the related host site must not be negative at any time,"[23] thereby establishing a net export prohibition. The current language in the PD is unclear in this regard. In this case, if the Rule 21 permits export to the grid, CESA understands that the aggregation of EVSEs are allowed in the PD to export to the grid up to that limit rather than a net-zero limit established in the Staff Proposal. However, this is muddled in the PD establishing that it will adopt the Staff Proposal. To avoid stranded export capacity, net exports to the grid should be affirmed and allowed.

IX. CONCLUSION.

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

Respectfully submitted,

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Date: November 10, 2021

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[22] PD Attachment 2 at 15.

[23] Staff Proposal at 10.