BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Distributed Energy Resources.	Rulemaking 14-10-003 (Filed October 2, 2014)

COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE ON THE PROPOSED DECISION ADOPTING PILOTS TO TEST TWO FRAMEWORKS FOR PROCURING DISTRIBUTED ENERGY RESOURCES THAT AVOID OR DEFER UTILITY CAPITAL INVESTMENTS

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**COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE
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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 *Proposed Decision Adopting Pilots to Test Two Frameworks for Procuring Distributed Energy Resources that Avoid or Defer Utility Capital Investments* ("PD"), filed by Administrative Law Judge ("ALJ") Kelly A. Hymes on January 5, 2021.

I. <u>INTRODUCTION</u>.

With the adoption of the Distribution Investment Deferral Framework ("DIDF") in 2018, the Commission established an important framework to provide transparency into the investor-owned utility ("IOU") distribution planning process through the Distribution Planning Advisory Group ("DPAG") and to identify key opportunities to deliver ratepayer cost savings through the deferral of traditional distribution investments via distributed energy resources ("DERs"). Since then, the Commission and stakeholders have improved the DIDF process and gained insights into the various challenges, barriers, and areas for improvement to efficiently and effectively source DERs to potentially defer distribution capital investments. While competitive solicitations have its comparative advantages as a sourcing mechanism, the Commission understood that there could be other means, such as tariffs or standard-offer contracts ("SOCs"), that could overcome the various challenges of DER procurement and increase the likelihood that DERs could address identified distribution grid needs.

Since then and with the issuance of this PD, the Commission has again asserted its leadership in creating innovative approaches to source and "procure" DERs to address distribution grid needs by leveraging the many improvements made to the DIDF and enhancing them through the adoption of two new frameworks as pilots. After more than two years of proposals, workshops, and comments on alternative sourcing mechanisms, the PD proposes to adopt a DER tariff pilot, dubbed the Partnership Program, a new SOC pilot, and several Request for Offer ("RFO") streamlining proposals for testing and implementation in the upcoming 2021-2022 DIDF cycle. We commend the Commission for these pioneering actions and are fully supportive of the Commission moving forward with adoption of these pilots and streamlining proposals.

In these comments, CESA focuses our recommendations on the Partnership Pilot since we largely support the SOC pilot and the streamlining RFO proposal. The latter two proposals will likely require the consideration of some implementation details, but they can be addressed in the DPAG process, where we will actively participate. Meanwhile, CESA supports many aspects of the Partnership Pilot, including the market certainty provided by the one-way adjustment to the cost cap, the use of acceptance triggers applied to the annual procurement goals to take advantage of ratable procurement approaches, the affirmation and clarification on incrementality policies, among others. While largely supportive and greatly appreciative of the Commission's leadership on the Partnership Program, CESA offers the following recommendations:

- The Revised Guiding Principles should be adopted with revisions to align with the current project-specific scope of the DIDF.

- Ratable procurement should be implemented through annual acceptance triggers and rolling subscription periods.

- Continuous subscriptions with minimal pauses between subscription periods improve customer experience and increase the odds of meeting the full deferral need.

- The reservation and performance payment tiers should be consolidated into a single reservation payment tier to reflect the nature of distribution grid needs and to ensure technology neutrality with wires investments.

- The prescreening criteria and application process should be centralized to apply to all utilities rather than potentially subjecting providers to duplicative processes for each utility.

II. <u>THE REVISED GUIDING PRINCIPLES SHOULD BE ADOPTED WITH REVISIONS TO ALIGN WITH THE CURRENT PROJECT-SPECIFIC SCOPE OF THE DISTRIBUTION INVESTMENT DEFERRAL FRAMEWORK</u>.

The PD revises the guiding principles as laid out in the October 6, 2020 Staff Proposal in ways that simplify and consolidate them so that they adhere to the definition of what principles should be and eliminate or omit various implementation details. We strongly support the PD's proposed revisions to the guiding principles and find that the revisions represent logical changes that are supported by the evidence in past Commission decisions and based on parties' comments. In particular, we agree with a fundamental principle that any DER procurement that comes out of the DIDF process, whether via the Partnership Program, SOCs, or RFO contracts, to represent a payment for a service, not an incentive.[1] This fundamental principle supplements some of the other principles, such as the one to leverage private investments and existing DERs and to avoid double payments. Furthermore, we support how one of the principles reflect the objective to

[1] PD at 13, 17, and 25.

encourage innovation.[2] Distribution deferral still represents a relatively new application of DERs as a procured and contracted grid service, such that the Commission should pursue iterative processes to address key challenges and barriers by refining existing and piloted sourcing mechanisms, as well as to consider different approaches in the future.

However, while supportive of the principles around cost-effectiveness CESA believes that several revisions need to be made to reflect how the DIDF is currently structured to assess very specific project-by-project opportunities instead of "overall" or "system" costs and benefits and to approve procurements when costs are reduced, not minimized. Typically, programs or tariffs are assessed for cost-effectiveness at an aggregate level, but the current DIDF is structured to screen and prioritize specific deferral opportunities, where DERs are assessed and procured if the cost of the distribution deferral service payments are lower than the cost cap of the specific planned investment. A DER's value relative to overall system costs is irrelevant under this structure and thus some of the revised principles in the PD could be misconstrued when assessing the success of the aforementioned pilots. Overall system costs could also be interpreted to encompass generation capacity and other avoided cost categories (*e.g.*, greenhouse gas emissions costs) that are not relevant to the current DIDF process or scope. Even as the "all costs" should considered (*e.g.*, including marketing and pre-screening costs) to determine cost-effectiveness, as explained in the PD,[3] the scope of the costs assessment should be focused on those incurred related to a specific distribution investment and deferral opportunity. To this end, Revised Principle 1 should be revised as follows:

> Provide a payment to distributed energy resource customers for distribution deferral resources, where the ~~**total**~~ costs to execute and maintain the distribution energy resource distribution deferral tariff reduces ~~**overall**~~

[2] PD at 15.

[3] PD at 17.

> ~~**energy system**~~ **distribution investment** costs, relative to other available options.

Additionally, several revisions are needed to reflect how the DIDF is currently structured to assess specific planned investment opportunities and approve procurements when costs are reduced, not minimized, relative to the cost of the planned investment. Whether a DER solution maximizes savings does not determine the approval of a DER solution as the DIDF is currently structured, so long as the contracted DER solution falls below the cost cap of the specific planned investment.[4] In light of this, CESA recommends the following changes to Revised Principle 4 to generally provide the key cost-saving objective of the Commission in developing these tariffs and pilots:

> Improve the deployment and utilization of cost-effective distributed energy resources for distribution deferral purposes, relative to other mechanisms currently available, to ~~**maximize**~~ **deliver** savings to ratepayers while also encouraging innovation of distributed energy resources.

Likewise, for many of the same reasons to modify Revised Principle 4, CESA also recommends a minor modification to Revised Principle 5 to ensure that the principles impose a relative, not a maximum/minimum, standard for DER procurement in line with how the DIDF is currently structured:

> Leverage private investment in distributed energy resources, including existing distributed energy resources participating in other Commission programs not already providing deferral services, to achieve distribution deferral benefits of ~~**least**~~ **lower** marginal cost to ratepayers.

CESA proposes these modifications to the PD's revised principles with an eye toward how they may be applied or construed in the future as the pilots are assessed and/or modifications or new mechanisms are implemented. Such clarification is needed to align with the project-by-project nature of the DIDF today. However, in the future, if the Commission considers the Planning

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[4] PD at 19.

Area Pilots (*i.e.*, CECI Pilot 2 and/or 3) for adoption and implementation as proposed in the Staff Proposal,[5] CESA believes that the our proposed modifications to the Revised Guiding Principles still apply even when DERs in a planning area will need to demonstrate cost-effectiveness when planned investment cost caps are pooled, such that the aggregate of DERs and planned investments are compared on relative basis.

III. RATABLE PROCUREMENT SHOULD BE IMPLEMENTED THROUGH ANNUAL ACCEPTANCE TRIGGERS.

CESA strongly supports the Commission's incorporation of ratable procurement approaches that enables the use of longer subscription periods within reason and supports behind-the-meter ("BTM") resource development processes.[6] The current IOU RFO processes require that DER solutions submit bids or offers to address the entire distribution grid need within the solicitation period (*e.g.*, typically 30-90 days), which presents barriers to BTM DER providers who would face challenges in building the customer project pipeline to fulfill that entire need and/or would entail dependence on other providers to build pipelines where the providers as a collective would constitute a portfolio that would address the full need. Unlike in-front-of-the-meter ("IFOM") DER projects that can identify, acquire, and build a site or multiple sites to have greater upfront assurances of their ability to meet the entire need, BTM DER providers require additional time to acquire multiple customers and build the pipeline of projects, which presents challenges to commit to doing so in a "procure-all-at-once" structure. These structural barriers to participating in competitive solicitations have borne out in the absence of BTM DERs being procured in the DIDF RFOs to date and the relatively low participation in solicitations. Thus, the

[5] Staff Proposal at 44-51.
[6] PD at 34 and 36.

ratable procurement approach better positions BTM resource types for success. At the same time, ratable procurement still meets and addresses the distribution grid need if structured in ways to establish subscription periods, annual procurement goals, and acceptance triggers that account for capacity and energy needs over time and accounts for the timing necessary for contingency solutions. CESA thus agrees with the Commission that ratable procurement better supports the expanded use of BTM resources and can have any risks related to over- or under-procurement through the acceptance trigger, 120% procurement margin, and annual procurement goals.

Importantly, CESA appreciates the clarification that the proposed 90% acceptance trigger will be set for each annual procurement goal that recognizes year-by-year needs.[7] As explained in our comments to the Staff Proposal, the key advantage of ratable procurement approaches is that it does not require full, upfront procurement for 100% of the maximum projected need during the deferral period but rather allows procurement to occur over time to meet year-by-year needs, thus deferring planned investments in lockstep on a year-by-year basis. The Staff Proposal may have intended this very structure, but this model was not made explicitly clear, leading CESA to suggest a lower acceptance trigger (*e.g.*, 32% in the El Casco project example used) that would be applied to the maximum 10-year capacity need during the deferral period.

By way of example, the same El Casco Project cited in our comments identified a 2.8 MW capacity need as the maximum required over a 10-year period in Summer 2029 and a 0.9 MW capacity need in Summer 2023.[8] Accordingly, we recommended an annual subscription period approach to set the acceptance trigger at 0.9 MW in the first-year subscription period, or 32% of

[7] PD at 37-38.

[8] *Comments of the California Energy Storage Alliance to the E-Mail Ruling Introducing Distributed Energy Resources Tariff Staff Proposal and Directing Comments and Responses to Questions* filed on October 30, 2020 in R.14-10-003 at 15-18. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M349/K793/349793491.PDF

the maximum 10-year capacity need during the deferral period, assuming that a tariff pilot was launched for this project in January 2021. As CESA understands the PD's clarification, the acceptance trigger would apply to this 0.9-MW capacity need as the "annual procurement goal" such that 0.81 MW of DERs would need to be subscribed to begin executing contracts with DER providers. If our understanding is correct, CESA supports this clarification and would even be open to moving the acceptance trigger to 100% of the annual procurement goal to provide assurances that grid needs are deferred by at least one year. In other words, for ratable procurement to take effect, the 90% acceptance trigger should not be set on the maximum 10-year capacity need during the deferral period.

IV. CONTINUOUS SUBSCRIPTIONS WITH MINIMAL PAUSES BETWEEN SUBSCRIPTION PERIODS IMPROVE CUSTOMER EXPERIENCE AND INCREASE THE ODDS OF MEETING THE FULL DEFERRAL NEED.

CESA recommends that the PD revise the process for setting the annual procurement goal in the annual refinement process.[9] Instead, the IOUs should be directed to establish annual procurement goals at the launch of the subscription period for all years of the deferral period, subject to potential revisions in the annual refinement process. In this way, the Partnership Program avoids the start-and-stop nature of program that pause subscriptions until the next-year need is refined, which can be harmful to customer experience with the program. Even after Year 1 needs are met, the program could simply open the next subscription period to allow continuous customer acquisition and BTM project development to start meeting needs for Year 2, with contracts executed only when 90% (or 100%) of the Year 2 acceptance trigger is met, and so on for all subsequent years. Such a structure would avoid the poor customer experience caused by waitlists and would improve overall DER portfolio viability in fully meeting the need for the entire

[9] PD at 38.

deferral period by minimizing pauses in the project development process. The goal, after all, is to fully defer the planned investment.

V. <u>THE RESERVATION AND PERFORMANCE PAYMENT TIERS SHOULD BE CONSOLIDATED INTO A SINGLE RESERVATION PAYMENT TIER TO REFLECT THE NATURE OF DISTRIBUTION GRID NEEDS AND TO ENSURE TECHNOLOGY NEUTRALITY WITH WIRES INVESTMENTS</u>.

Compared to the Staff Proposal, the PD maintains the deployment, reservation, and performance payment tiers to address barriers related to DER adoption and increase the likelihood of meeting deferral needs, while eliminating the test payment tier as a simplifying measure and because this is already required in the technology neutral *pro forma* ("TNPF") contract. Out of the total cost cap for a given planned investment, the PD also specifies that 20% is allocated to the deployment payment, 30% to the reservation payment, and 50% to the performance payment.[10] CESA agrees with the elimination of the test payment tier as being unnecessary and generally supports the 20% allocation for the upfront payment tier to support new resource adoption and deployment and at the same time balancing against potential stranded cost risks. However, CESA recommends that the performance payment tier to be eliminated, with their 50% allocation of the cost cap consolidated in the reservation payment tier, leading to an 80% total allocation, along with performance-based adjustments to the reservation payment amount based on actual performance and dispatch. CESA makes this recommendation for four key reasons.

First, to adhere to the guiding principle that DERs operate on a level playing field as traditional infrastructure investments, DERs should be similarly paid for the capacity that they commit to providing. Under the performance payment tier as proposed in the Staff Proposal and as adopted in the PD, providers are not paid if the grid need does not arise, which is justified as

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[10] PD at 43-46.

increasing the cost-effectiveness and allowing for over-procurement to address changing grid needs.[11] Wires, by comparison, are "paid" for the full capacity of the line, circuit, or substation investment and do not have their cost recovery adjusted for the actual usage of the wires capacity. Whether for the traditional planned investment or for the DER alternatives, the value is in the committed capacity to address forecasted distribution grid need. Otherwise, DERs would be subject to significant amounts of "lost" payment if the grid need does not arise as frequently as expected.

Second, the pursuit of increased cost-effectiveness is misplaced justification for establishing a performance payment tier since, by default, the Partnership Program already sets the tariff budget at a certain percentage (85%) that ensures ratepayer savings.[12] A structure intended to deliver even more ratepayer savings is desirable but is unnecessary for the purposes of cost-effectiveness. As discussed above, the DER should not be subject to a cost minimization standard since they are already providing ratepayer value by delivering cost savings compared to the wires alternative. Furthermore, our understanding of the 120% procurement margin is that this level of DER procurement would fall within the tariff budget. For example, even if 10 MW of distribution capacity is needed to defer a $10-million planned investment, the Partnership Program would allow up to 12 MW of tariff subscriptions within an $8.5-million tariff budget to improve the odds of success for deferral by the DER alternative while still ensuring cost-effectiveness, by virtue of the 12 MW being procured with a tariff budget set at 85% of the cost cap. As such, there is no need to increase cost-effectiveness to account for the procurement margin because the added 20% margin is already deemed cost-effective.

[11] Staff Proposal at 32.
[12] PD at 39.

Third, any performance-related concerns can be reflected in adjustments to the reservation payment, as done in other generation capacity contracts. If measured performance in response to IOU dispatch falls short relative to the reserved capacity, the reservation payment can be adjusted through a derate so that it is lower and can only be increased back to its original level upon demonstrating consistent performance up to their committed/contracted level. For example, if a DER performs below, say, 95% for any given dispatch, the reservation payment could be reduced by 5%, which ensures that DERs perform up to their contracted value. Performance below some standard, say 90%, could then lead to the DER losing its reservation payment for that month and being subject to additional testing regimes to re-qualify for reservation payments. The performance levels, scale for derating reservation payment levels, and threshold for voiding reservation payments could be subject to implementation-focused discussions in the DPAG, but the larger point is that actual performance can be captured through a reservation payment tier alone.

Fourth, while the Staff Proposal contemplates a situation where grid needs may not arise as frequently as forecasted, it does not address the reverse situation where grid needs turn out to be more frequent than forecasted, such that additional performance payments are needed, which could exceed the amount allocated to the performance payment tier. Consequently, the DER provider would potentially be subject to no payments for excessive deliveries beyond the forecast, which would not provide the DER with the incentive to perform. Or, if payments must be made, it could lead to reduced cost-effectiveness by having to pay more for performance than was allocated. Under a structure with a consolidated reservation payment tier, there is some more flexibility around the number of dispatches since DERs would be paid for performance-adjusted capacity, though there should be some bounds or upfront expected operational requirements on the number of dispatches.

Finally, the potential for "lost" payments under a performance payment tier if dispatch is not needed works against the objective of supporting DER adoption and deployment. The potential for less service payments only serves to decrease the viability of DER projects.

For all the reasons above, CESA recommends that the Commission eliminate the performance payment tier and establish an 80% allocation for the reservation payment tier, with adjustments to reflect actual performance. Alternatively, if the Commission wishes to maintain these three tiers, CESA recommends a greater allocation to the reservation payment tier (50%) and reduced allocation to the performance payment tier (30%).

VI. THE PRESCREENING CRITERIA AND APPLICATION PROCESS SHOULD BE CENTRALIZED TO APPLY TO ALL UTILITIES RATHER THAN POTENTIALLY SUBJECTING PROVIDERS TO DUPLICATIVE PROCESSES FOR EACH UTILITY.

The PD finds that prescreening is worthwhile to test and could lead to improvements in the solicitation process, with the intent of the process being the "general" assessment of minimum DER provider viability (*e.g.*, experience, financial strength, and performance ability) while ensuring technology neutrality and not inhibiting new market entrants. Additionally, the PD maintains IOU-specific processes to provide them with flexibility and accommodate their different grid needs and grid architectures.[13] Importantly, the prescreening process would apply to all sourcing mechanisms, including not only the Partnership Program but also the SOC pilot and the existing DIDF RFO mechanism. As expressed previously in comments to the Staff Proposal, CESA generally supports the prescreening criteria and process as potentially streamlining the "procurement" process by verifying minimum provider viability, so long as the administrative burden is not excessive and does not preclude new market entrants. As the PD explains, these new

[13] PD at 32-33.

criteria and processes should verify "general capabilities" of potential market participants, where such verification can reduce the risks of project development attrition/cancellation or underperformance that cause the distribution grid need to not be or insufficiently deferred.

However, given the intent of the prescreening process and criteria, CESA does not see a need to subject DER providers to duplicative prescreening processes for each IOU. Despite the differences in grid architecture, CESA does not understand why IOU-specific processes are needed if general capabilities are being assessed. Especially as the Commission has already directed or encouraged the IOUs to standardize the four distribution grid services (*i.e.*, distribution capacity, back-tie reliability, microgrid resiliency, voltage support) and operational requirements (*e.g.*, day-ahead dispatch),[14] CESA sees little need to subject DER providers to duplicative prescreening processes, which only adds administrative burden. Considering prescreening costs will be applied to the cost-effectiveness assessment of DER solutions,[15] unnecessary costs will be incurred without added benefit, thereby reducing the likelihood of DER solutions being procured. As a result, CESA recommends that the prescreening criteria be uniform and the prescreening process be centralized such that any interested DER provider be subject to one application submittal and verification requirement. To achieve this, CESA proposes that a single IOU or third-party entity could serve this role, with the costs allocated proportionately.

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[14] *See, e.g.*, Reform 47 in Attachment A of *Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Filing and Process Requirements* issued on May 11, 2020 in R.14-08-013, *et al.* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M337/K288/337288441.PDF

[15] PD at 34.

VII. CONCLUSION.

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

Respectfully submitted,

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