BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 E) Proposing Framework for Substation Microgrid Solutions to Mitigate Public Safety Power Shutoffs.	Application 21-06-022 (Filed June 30, 2021)

RESPONSE OF THE CALIFORNIA ENERGY STORAGE ALLIANCE ON THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) PROPOSING FRAMEWORK FOR SUBSTATION MICROGRID SOLUTIONS TO MITIGATE PUBLIC SAFETY POWER SHUTOFFS

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In accordance with Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the California Energy Storage Alliance ("CESA") hereby submits this response on the *Application of Pacific Gas and Electric Company (U 39 E) Proposing Framework for Substation Microgrid Solutions to Mitigate Public Safety Power Shutoffs* ("Application"), submitted by Pacific Gas and Electric Company ("PG&E") on June 30, 2021.

I. INTRODUCTION.

The Commission issued Decision ("D.") 21-01-018 to establish an interim approach to use temporary generation for 2021 and establish a process and parameters by which the investor-owned utilities ("IOUs") would transition to clean temporary generation and/or substation-level microgrid solutions. In line with D.21-01-018, PG&E submitted this Application on June 30, 2021 proposing a comprehensive methodology to identify and procure substation-level generation-based microgrid solutions to mitigate outages caused by Public Safety Power Shutoff ("PSPS") events and to supersede the adopted interim approach. Specifically, PG&E proposed a three-step process to analyze PSPS mitigation alternatives for at-risk substations, followed by a procurement process and framework for soliciting single-season and/or multi-season solutions at identified, specific substations.

CESA is directionally supportive of PG&E's efforts to establish a comprehensive framework to systematically assess opportunities for substation-level microgrids that face future PSPS risks. Through a regular and transparent process, PG&E will be able to more thoroughly consider where clean microgrid solutions could feasibly and more cost-effectively address PSPS outage risks. As discussed further in our response below, CESA is generally supportive of many elements of the framework, with certain modifications and clarifications.

At the same time, CESA believes that the Application should be viewed in the context of PG&E's Advice Letter 6204-E, *Evaluation of Clean Substation Pilot Project Opportunities Pursuant to D.21-01-018*, as well as the experiences and lessons learned of recent competitive solicitations intended to procure clean substation-level microgrid solutions. In these instances, PG&E made conclusions on the infeasibility of clean substation alternatives based on Request for Proposals ("RFPs") that was structured in a way that was all but doomed to fail in terms of its ability to elicit robust market participation and a diversity of solutions, leading PG&E to instead propose in Advice Letter 6204-E to leverage its Base Interruptible Program ("BIP") and SmartAC Program to use participating demand response ("DR") resources for PSPS events as well. In our protest to Advice Letter 6204-E submitted on June 29, 2021, a day prior to the submission of this Application, CESA detailed these flaws and incorporate many of our same concerns in this response.

Overall, the proposed framework in the Application represents improvements upon the approach and conclusions reached in Advice Letter 6204-E. Among those improvement areas include the willingness or openness to consider both in-front-of-the-meter ("IFOM") and behind-the-meter ("BTM") resources as a portfolio of solutions that could reduce diesel usage and/or shape the load requirements at the substation and a systematic and comprehensive process to assess substation-specific needs and requirements. In our response below, we highlight areas of further refinement or clarification regarding these improved components of the framework but also point to additional areas that should be reflected and incorporated in the adopted framework.

II. BACKGROUND AND INTEREST IN THE PROCEEDING.

CESA is a 501c(6) membership-based advocacy group committed to advancing the role of energy storage in the electric power sector through policy development, education, outreach, and research in an effort to support a more affordable, efficient, reliable, safe, and sustainable electric power system for all Californians. With over 100 companies represented in the energy storage ecosystem, CESA has a direct interest in the proceeding in shaping the policies, procedures, and rules for substation-level microgrid solutions being contemplated in the proposed framework in the Application. Energy storage is often a critical resource and technology type included in microgrid projects, where CESA's unique perspective will be important and cannot be fully represented by any other party or stakeholder. CESA also has been an active participant in related rulemakings, such as the proceedings for Microgrids (R.19-09-009), De-Energization (R.18-12-005), Reliable Electric Service in Extreme Weather (R.20-11-003), Distributed Resource Planning (R.14-08-013, *et al.*), Integrated Distributed Energy Resources (R.14-10-003), Integrated Resource Planning and Procurement (R.16-02-007, R.20-05-003), and Resource Adequacy (R.19-11-009).

III. <u>ISSUES TO BE CONSIDERED</u>.

In this response, while directionally supportive of the Application, CESA offers the following comments on PG&E's proposed scope of the Application, along with additional areas for consideration over the course of this proceeding.

A. The methodology to identify candidate substations should not solely rely on historical analysis and should be explored for further refinement.

In its proposed three-step process, after screening out projects with committed and planned grid-based investments, PG&E would conduct a historical 10-year lookback analysis to identify specific substations with unmitigated, residual PSPS risk.[1] However, CESA has concerns that a historical analysis may have limited predictive power or may overlook areas with unmitigated PSPS risk. Whether through alternative or complementary forward-looking methodologies, or through a greater weighting of recent historical years, the Commission should consider whether the proposed historical analyses sufficiently identify all at-risk substations.

Furthermore, the Commission should explore whether historical weather years will sufficiently capture extreme weather risks that lead to PSPS events. In other resource planning proceedings (*e.g.*, for RA in R.19-11-009, IRP in R.20-05-003, and Emergency Reliability in R.20-11-003), the Commission is actively contemplating or have adopted interim planning targets around higher margins to account for the recent and continued

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[1] PG&E Prepared Testimony *Chapter 3 Framework for Comparing Substation Microgrid Solutions Against Other PSPS Mitigation Alternatives: Witness Mark Esguerra* at 6-9.

extreme heat and drought events, all of which are also conducive to wildfires. Rather, to accurately capture future PSPS risk and identify at-risk substations, future-looking forecasts and extreme weather events should be modeled to determine needs.

B. The PSPS mitigation need should be developed specific to the substation.

PG&E details the eligibility requirements for substation-level microgrid solutions to mitigate PSPS risks, which includes the ability to island for at least 48 hours as well as other technical requirements (*e.g.*, cold load pickup, black start, frequency and voltage regulation). A benefit to PG&E's proposed approach is the ability to specify the eligibility and load requirements upon conducting PSPS risk modeling using PG&E's proposed three-step process.[2] In doing so, the actual need may deviate from the base or across-the-board minimum requirements set forth in Appendix guidance from D.21-01-018. For example, upon substation-specific modeling, PG&E may find that the islanding requirement may not need to be set at 48 hours or 96 hours, as done in D.21-01-018 or in previous solicitations, thereby increasing the potential to rely on cleaner alternatives such as solar and energy storage resources. This type of custom specification of need and requirements mirrors the approach used for the Distribution Investment Deferral Framework ("DIDF") and should be incorporated as part of the adopted framework.

Furthermore, lessons learned from the DIDF process should also be incorporated into this framework. As part of the proposed three-step process, PG&E shares how the historical analysis will be updated annually, presumably across a rolling 10-year historical lookback period.[3] To provide certainty in the procurement process, the framework should avoid "moving targets" with changing needs where possible, particularly for multi-season and long-term resource investments that require certainty on procurement parameters.

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[2] PG&E Prepared Testimony *Chapter 5 Investment Planning Framework for Substation-Level PSPS Mitigation Solutions: Witness Quinn Nakayama* at 7.

[3] PG&E Prepared Testimony *Chapter 3 Framework for Comparing Substation Microgrid Solutions Against Other PSPS Mitigation Alternatives: Witness Mark Esguerra* at 9.

C. Procurement process and proposed schedule should be expedited where possible.

PG&E laid out potential schedules for the competitive solicitations to procure single-season and multi-season solutions that would involve contract approval by the Commission by May 2023 and March/August 2024, respectively.[4] CESA understands that the timelines were proposed based on the regulatory process involved in approving the framework in this Application, in addition to engagement with local communities and agencies. With such protracted timelines, CESA is concerned that the usefulness of any microgrid solutions will also be delayed far into the future, as late as the 2025 or 2026 wildfire timelines given the additional deployment timelines required to bring resources and solutions online after Commission approval of contracts. Even if single-season solutions are deployed in the interim until multi-season solutions are delivered, the Commission should consider whether the proposed regulatory schedule to approve and/or modify the framework can be expedited and whether the solicitation process timeline is appropriate.

D. The consideration of a portfolio of IFOM and BTM solutions should be made more explicitly clear.

At various points of the Application, PG&E discusses the potential of BTM and IFOM resources to constitute a portfolio or mix of distributed energy resources ("DERs") that can address the PSPS mitigation need.[5] Along similar lines, PG&E is proposing refinements to the greenhouse gas ("GHG") emissions and criteria pollutants standards from D.21-01-018 to apply to a team of DER technologies rather than any single technology,[6] suggesting that PG&E is open to taking a portfolio approach to substation-level PSPS mitigation. This portfolio approach could be extended not only to the emissions-related and environmental standards but also in terms of meeting the actual islanding needs. On the other hand, PG&E also discusses how there are limits to BTM generation being able to scale sufficiently to address the space constraint issue for

[4] PG&E Prepared Testimony *Chapter 5 Investment Planning Framework for Substation-Level PSPS Mitigation Solutions: Witness Quinn Nakayama* at 3-6.

[5] PG&E Prepared Testimony *Chapter 4 Framework for Transitioning to Clean Solutions to Mitigate PSPS Outages at Substations (Public): Witness Claire Halbrook* at 14.

[6] *Ibid* at 13-14.

substation-level IFOM microgrid solutions and how energy storage has been shown to only be able to address a portion of the energy need at identified substations.[7]

Despite alluding to the potential and/or limits of IFOM and BTM solutions to address PSPS mitigation needs, the framework should more explicitly affirm their eligibility as viable alternatives and consider how the identified need can be scoped to allow innovative approaches involving both IFOM and BTM solutions to be procured as a result. As discussed by PG&E, BTM resources can shape the load requirements, potentially even narrowing the load requirements if operationalized and/or contracted in certain ways, such that any substation-level microgrid solution can rely increasingly on IFOM renewables and energy storage resources. To this end, similar to its approach for GHG emissions and pollutants standards, PG&E should also affirm that a portfolio or mix of DERs can also be used to address the eligibility and performance requirements for the PSPS mitigation need, even though any single technology or resource within the portfolio would not be able to meet these requirements on its own.

E. Load-modifying programs or microgrid tariffs should be modified, extended, or created to reduce diesel usage and shape load requirements at all candidate substations.

Even as PG&E only issues competitive solicitations to procure and contract for microgrid solutions for candidate substations in accordance with its proposed three-step process, CESA recommends that this framework more comprehensively consider how new load-modifying programs could be created, or existing load-modifying programs could be modified or extended to reduce diesel usage. This is a pilot concept proposed by PG&E in Advice Letter 6204-E and could be incorporated into the proposed framework in this Application. Given that PSPS events are last-resort measures, PG&E will want to mitigate any identified PSPS risks that cross their established threshold with temporary generators. Any final portfolio is also envisioned by PG&E as requiring a reserve of mobile temporary generation due to the uncertainty associated with the scope, scale, and duration of PSPS events.[8] Rather than reserving and relying on temporary diesel-fueled generation as a

[7] *Ibid* at 2-4 and 8.

[8] PG&E Prepared Testimony *Chapter 2 Framework for Determining Substations Most Likely to be Impacted by Transmission Related PSPS Outages: Witness Mark Esguerra* at 9.

backstop, the adopted framework should seek to leverage existing or new load-modifying programs for distribution resiliency, with expanded incentives or budgets to support the additional services provided.

If DR solutions are considered as part of a broader portfolio strategy, CESA recommends that the framework consider the merits of establishing or expanding deployment and/or performance-based incentives for BTM energy storage solutions, which are capable of frequent dispatch and cycling in response to lengthy PSPS events. Even if these BTM storage solutions do not offset the entire PSPS mitigation need at the substation level, it reduces diesel usage and narrows the load requirements that may make it more feasible for different IFOM microgrid solutions.

Finally, CESA observes that the procurement side of the proposed framework relies on competitive solicitations to procure the PSPS mitigation alternatives. However, considering observed challenges with recent competitive solicitations, the Commission should examine whether alternative sourcing mechanisms beyond competitive solicitations should be developed or adopted. Tariffs, for example, support more bottom-up microgrid and BTM resource development that could shape the load need at the at-risk substations and could have its operations guided by price signals or performance requirements that align with reduced diesel usage. To this end, the Commission could adopt a tariff that signals and compensates for avoided diesel usage for all resources impacted by a PSPS event at a substation and able to respond. Such approaches could streamline and scale PSPS mitigation alternatives while right-sizing for the residual PSPS mitigation need with IFOM resources.

F. The application of the cost cap adopted in D.21-01-018 should be clarified as it relates to the cost-effectiveness analysis and opportunities for value stacking.

CESA appreciates and generally agrees with PG&E's flexible consideration of PSPS microgrid alternatives relative to the cost cap established in D.21-01-018, where contracts would be targeted toward those that fall at or below the price benchmark but allow for flexibility to consider resources that may exceed the benchmark. In cases of the latter, PG&E explained that a higher standard of review would be sought via Tier 3 Advice Letter (instead of the Tier 2 advice letter process for contracts falling below the price benchmark),[9] which CESA views as appropriate given the multitude of values being provided from the same resource. This is consistent with the guidance provided related to the DIDF, where the Commission recently adopted reforms that affirmed that deferral projects may exceed their cost cap if they are able to simultaneously satisfy various regulatory procurement objectives.[10]

However, a key policy question is how the Commission will establish the "primary function" of such dual-use or multi-use resources that address not only PSPS resiliency but also other procurement objectives, which has direct impacts on cost-effectiveness assessments and the appropriate cost recovery mechanism. On the one hand, the critical importance of PSPS resiliency could suggest that the distribution service is the primary function and costs should be recovered via distribution rates, as proposed by PG&E;[11] on the other hand, services like Resource Adequacy ("RA"), if contracted, are utilized on a more frequent basis such that its primary function could be determined to be the blue-sky services of the contracted resource(s), whereby the costs should be recovered via generation rates. Clarity is needed on how value-stacked resources will be considered in cost-effectiveness analysis and how it relates to the cost cap, and how cost recovery will be established based on these multiple value streams.

Without endorsing or favoring one, PG&E also envisioned three possibilities for contract structures for resources procured as a result of this framework: bundled contract for both PSPS and blue-sky products; separate contract for PSPS and blue-sky products; and contract for PSPS product only, with the seller able to market and contract for blue-sky services with other load-serving entities ("LSEs").[12] While it is appropriate to be open to all possibilities at this time, this proceeding should consider whether the framework

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[9] PG&E Prepared Testimony *Chapter 5 Investment Planning Framework for Substation-Level PSPS Mitigation Solutions: Witness Quinn Nakayama* at 16; and *Chapter 6 Framework for Recovery and Allocation of Costs Associated with Substation-Level PSPS Mitigation Solutions: Witnesses Donna L. Barry and Rebecca Madsen* at 2.

[10] *Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework – Filing and Process Requirements* filed on May 11, 2020 in R.14-08-013, *et al.* at 46.

[11] PG&E Prepared Testimony *Chapter 6 Framework for Recovery and Allocation of Costs Associated with Substation-Level PSPS Mitigation Solutions: Witnesses Donna L. Barry and Rebecca Madsen* at 8.

[12] PG&E Prepared Testimony *Chapter 6 Framework for Recovery and Allocation of Costs Associated with Substation-Level PSPS Mitigation Solutions: Witnesses Donna L. Barry and Rebecca Madsen* at 9.

should narrowly focus on PSPS-related distribution resiliency, which can simplify and streamline the procurement and contracting process and clarify the appropriate cost recovery approaches, while still leaving open the possibility for blue-sky services to be contracted or pursued separately outside of this framework.

G. The application of the cost cap adopted in D.21-01-018 should be incorporate the value of resiliency if adopted.

CESA appreciates and agrees with PG&E's recognition that the Resiliency and Microgrid Working Group ("RMWG") in R.19-09-009 is currently in the process of discussing and developing a value of resiliency, which if adopted, could result in changes to the framework.[13] At this stage, it is too early to tell what the value of resiliency should be, how it should be calculated, and even whether it would be adopted in a way to be incorporated into program cost-effectiveness calculations or as part of the cost-effectiveness assessment of competitive solicitations. However, the value of resiliency represents a critical benefit that should be incorporated if adopted. The adopted framework should be adaptable to this important policy determination.

IV. CATEGORIZATION, HEARINGS, AND SCHEDULE.

CESA agrees with PG&E's proposed categorization of the proceeding as "ratesetting" but does not have a position at this time on whether evidentiary hearings will be necessary.

However, CESA has concerns with PG&E's proposed schedule of the proceeding to have the Commission consider and approve its Application with a Proposed Decision in February 2022 and Final Decision in March 2022. While certain aspects of the proposed framework may be more complex and could require further discussion and discovery, CESA is concerned that the resolution of this Application by March 2022 will leave little time for the framework to be implemented in time for the 2022 wildfire season. Substation risk assessments and subsequent procurements to address identified needs will need to be conducted. As a result, any clean microgrid solutions

[13] PG&E Prepared Testimony *Chapter 1 Introduction and Overview: Witness Fong Wan* at 8; and *Chapter 4 Framework for Transitioning to Clean Solutions to Mitigate PSPS Outages at Substations (Public): Witness Claire Halbrook* at 16-17.

procured as a result of this framework would come for the 2023 wildfire season at the earliest, thus extending the interim approach that relies on the use of diesel generators.

To this end, the Commission should consider establishing a schedule that involves a Final Decision to be issued in December 2021.

V. CONCLUSION.

CESA appreciates the opportunity to submit this response on the Application and looks forward to collaborating with the Commission and stakeholders in this proceeding.

Respectfully submitted,

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