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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 25-10-003 (Filed October 9, 2025)

OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE ORDER INSTITUTING RULEMAKING TO OVERSEE THE RESOURCE ADEQUACY PROGRAM

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Dated: November 4, 2025

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I. INTRODUCTION

Pursuant to the *Order Instituting Rulemaking* ("OIR") initiating this proceeding, issued by the California Public Utilities Commission ("Commission") on October 15, 2025, and in accordance with Rule 6.2 of the Rules of Practice and Procedure of the Commission, Pacific Gas and Electric Company ("PG&E") provides these opening comments on preliminary matters pertaining to scope, schedule, and administration of the proceeding, as requested in the OIR.

Sections II and III of these comments provide PG&E's recommendations related to the preliminary scoping memo and preliminary schedule/determinations, respectively. In Section II, PG&E first recommends bifurcating Track 1 of this proceeding dedicated to refinements and modifications of the resource adequacy ("RA") program so that proposals related to Issue 7 (Transactability Issues within the SOD Framework) can be better informed by the Commission's Energy Division Staff's forthcoming report evaluating transactability issues within the slice-of-day ("SOD") framework. Section II of these comments also responds to Issue 10 (Refinements to the Resource Adequacy Program) by identifying the following issues relating to refinements of the RA program that PG&E believes should be addressed in Track 1 of this proceeding, in order of priority:

- Revisions to the local capacity requirement ("LCR") reduction compensation mechanism ("RCM") calculation data set;
- Clarification to the list of events that do not qualify as "load migration" for purposes of the RA load forecast process;
- Central Procurement Entity ("CPE") compensated self-shown resource re-marketing issues;
- Demand Response ("DR") exports for the RA program; and
- Updates to RA rules associated with large load facility generation resources.

Section III of these comments proposes a slight modification to the preliminary schedule, building upon PG&E's recommendation to bifurcate Track 1 of this proceeding, dedicated to refinements and modifications of the RA program. PG&E respectfully requests that the Commission adopt its recommendations for the reasons discussed herein.

II. COMMENTS ON THE PRELIMINARY SCOPING MEMO

With one notable exception, PG&E supports the preliminary scoping memo set forth in the OIR. The preliminary scoping memo indicates that the proceeding will be organized into two tracks, with one track considering refinements and modifications to the RA program (i.e., Track 1) and the other track addressing system, flexible, and local capacity requirements by June 2025 (i.e., Track 2). PG&E recommends that the Commission further bifurcate Track 1, dedicated to RA program refinements and modifications, into Track 1.A and Track 1.B, so that proposals related to all Track 1 issues but Issue 7 (Transactability Issues within the SOD Framework) will be filed in Track 1.A on January 23, 2026. PG&E recommends that proposals related to Issue 7 be filed in Track 1.B, after parties have had an opportunity to review thoroughly Energy Division Staff's report on potential transactability issues under the SOD framework.

While PG&E does not object to consideration of transactability issues within this proceeding, PG&E is concerned that parties may not be able to file fully informed proposals on Issue 7 alongside all other Track 1 party proposals by January 23, 2026. The OIR notes that Decision ("D.") 25-06-048 authorizes Energy Division Staff to produce a report evaluating transactability issues within the SOD framework in the first quarter of 2026.[1] Parties should be afforded sufficient time to review and understand Energy Division Staff's report prior to formulating their proposals on Issue 7. Given that the report is expected in the first quarter of 2026, PG&E requests that the Commission defer consideration of proposals related to Issue 7 to Track 1.B, with a proposed schedule for the additional sub-track outlined in Section III below.

PG&E further supports the Commission's plan to limit the number of refinements to be considered for each track of this proceeding and urges the Commission to consider each of the refinements to the RA program listed below in priority order for PG&E.

1. Revisions to the LCR-RCM Calculation Data Set

The Commission should consider whether the current data set for calculating the LCR-RCM price should be aligned with the revised methodology and data set for the system RA Market Price Benchmark ("MPB") used in establishing the Power Charge Indifference Adjustment ("PCIA") rate. In D.20-12-006, the Commission adopted the LCR-RCM to apply to new preferred resources and new energy storage resources eligible for procurement by a CPE.[2] The LCR-RCM allows load serving entities ("LSE") to self-show preferred local resources to a CPE in exchange for compensation, not to exceed the pre-determined LCR-RCM price[3] and is intended to incentivize the development of new preferred local resources. The current data set used to calculate the pre-determined LCR-RCM price, which was modified in D.22-03-034,

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[1] D.25-06-048, Ordering Paragraph ("OP") 11.
[2] D.20-12-006, OP 3.
[3] *Id.*, OP 3(c).

utilizes the weighted average price from the last four quarters of the PCIA data responses for system and local RA transactions, and subtracts the system RA price from the local RA price. This calculation was adopted by the Commission because it was determined that the use of weighted average prices (as used in setting the PCIA RA MPB) are a good proxy for determining the incremental value (i.e., premium) of a local RA resource.[4]

Given the recent changes to the PCIA RA MPB methodology and underlying data set, PG&E believes that the Commission should scope for consideration whether and how the data set for the calculation of the pre-determined LCR-RCM price should align with the revised PCIA RA MPB methodology. In D.25-06-049, the Commission adopted changes to the calculation of the PCIA RA MPB to expand the transaction data set window and remove affiliate, swap, and sleeve transactions, and it may be reasonable to apply these same revisions to the calculation of the pre-determined LCR-RCM price.

2. Clarification to List of Events that Do Not Qualify as Load Migration for Purposes of the RA Load Forecast Process

The Commission should clarify in this proceeding whether a deviation between the effective date confirmed by Energy Division in a letter certifying an LSE's implementation plan (or amendment thereto) and the planned date to begin service communicated by such LSE during the load forecast process qualifies as "load migration" for purposes of the RA program. Beginning with D.04-10-035 and D.05-10-042, the Commission adopted the RA program's load forecast adjustment methodology, in which LSEs were directed to submit load forecasts to the California Energy Commission ("CEC") that would be adjusted for coincidence and program impacts and assessed for plausibility and consistency with the CEC's aggregate forecast. The RA forecast adjustment methodology was further refined in several decisions, including D.10-

[4] *Id.*, Finding of Fact 5.

13-039, D.11-06-022, D.12-06-025, D.17-06-027, and D.19-06-026. In D.19-06-026, the Commission sought to standardize the assumptions used by LSEs to develop their load forecasts. To that end, the Commission ordered that "load migration" is the only allowable reason for differences between initial and final year-ahead load forecast submittals in March and August, respectively.[5] For purposes of the RA program, the Commission defined the term "load migration" to mean load effects that: (1) result from one or more customers' retail electric service transferring directly from one LSE to another LSE in the same Transmission Access Charge (TAC) area, and (2) an LSE cannot reasonably predict and include in an implementation plan or in an initial year-ahead load forecast.[6] The Commission further clarified that load migration does not include changes to approved implementation plans.[7]

Notwithstanding the foregoing, it appears that an LSE with an approved implementation plan (or an approved amended implementation plan) could seek to make changes between its initial and final year-ahead load forecast based on a voluntary delay in the effective date of service (or expanded service) that was previously confirmed by Energy Division in a letter of certification. If an LSE were to submit a change to its approved implementation plan to reflect the voluntary delay, it is clear from D.19-06-026 that such a change would not qualify as load migration and, therefore, could not form the basis of a difference between the LSE's initial and final load forecasts. However, such a voluntary delay by the LSE may not result in submittal of a changed implementation plan (perhaps depending on the specific language in the implementation plan), and confusion may result as to whether the voluntary delay qualifies as "load migration" if no change to an approved implementation plan is submitted.

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[5] D.19-06-026, OP 10.
[6] *Id*., OP 11.
[7] *Id*., OP 12.

Given this potential confusion and the uncertainty it may create regarding procurement responsibility for RA program obligations, PG&E requests that the Commission specify in this proceeding whether a deviation between the effective date confirmed by Energy Division in a letter certifying an LSE's implementation plan (or amendment thereto) and the planned date to begin service communicated by such LSE during the load forecast process qualifies as "load migration" for purposes of the RA program.

3. CPE Compensated Self-Shown Resource Remarketing Issues

The Commission should clarify in this proceeding (A) whether an LSE that shows a local resource to a CPE for compensation is entitled to remarket the shown capacity to another LSE and retain eligibility for compensation under the LCR RCM and (B) if so, what modifications to the agreement or payment terms between the CPE and the original showing LSE must be made (and/or what new agreement or payment terms must be established with the purchasing LSE), if any, given that the initial showing LSE will no longer intend to self-show the sold local resource on annual and monthly RA plans to satisfy its system and/or flexible RA needs as required by OP 2 of D.22-03-034.

OP 15 of D.23-06-029 appears to contemplate that any LSE that has self-shown a local resource to the CPE for compensation may sell that capacity to another LSE subject to certain requirements;[8] however, no Commission decision appears to contain clear guidance on whether the selling LSE is still entitled to compensation under the LCR RCM or how the existing agreement or payment terms with the selling LSE should be handled in the event of such a sale. Due to this gap, it remains unclear if and how a CPE should process LCR RCM payments for a remarketed compensated self-shown resource. As such, PG&E recommends this issue be scoped into the initial track of this proceeding for further consideration and clarification.

[8] D.23-06-029, OP 15.

4. DR Exports for the RA Program

Behind-the-meter ("BTM") energy storage has been an underutilized resource for DR, as exported volumes do not have an RA value. As energy storage has become more widely adopted by both residential and non-residential customers, the potential capacity this BTM resource can make available to the grid continues to increase. On July 29, 2025, a virtual power plant that consisted of over 100,000 residential batteries was dispatched for two hours across the service territories of PG&E and Southern California Edison Company simultaneously. The test event produced 535 megawatts of capacity. Unfortunately, such a resource does not qualify for export compensation, nor RA, limiting the impact such a resource can have on reliability and affordability.[9]

Previously, the Commission noted in D.20-06-031 that BTM resources may continue to participate in the RA program as DR resources;[10] however, the load impact from energy storage in a DR program can only be recognized up to the entirety of the delivered load. In other words, the DR load impact does not count any net export from a battery. This presents a barrier to scaling BTM storage in California.

In the same decision, the Commission identified eight issues that must be addressed before counting BTM export for RA. These are:

> 1) forward determination of capacity associated with renewable production, consumption, charging, and export;
>
> (2) RA requirements associated with customers providing capacity;

[9] Brattle, *Assessing VPP Performance: Impacts of a Test Event in California*, August 1, 2025, available at https://www.brattle.com/wp-content/uploads/2025/08/Assessing-VPP-Performance-Impacts-of-a-Test-Event-in-California-1.pdf.
[10] D.20-06-031, p. 33 ("We note that hybrid BTM resources may continue to participate in the RA program as DR resources").

(3) wholesale market participation including metering, dispatch control, and communication with the California Independent System Operator Corporation ("CAISO");

(4) cost for energy associated with consumption, charging, and export,

(5) changes such that net energy metering ("NEM") and self-generation incentive program ("SGIP") resources are compensated for capacity, while discounting for their NEM and SGIP compensation as necessary to ensure that the resources do not receive compensation beyond their value;

(6) load forecasting and adjustment for BTM resources;

(7) interaction of such resources with existing BTM resources such as proxy DR; and

(8) deliverability determination.[11]

Given the increasing volume of BTM resources that could contribute to greater system and local reliability and affordability, PG&E recommends the Commission include this issue in scope for tracks 1 and 2 of this proceeding for DR.

PG&E acknowledges that DR exports pertain to both DR and RA. The issue should also be included in the scope of the Rulemaking 25-09-004, which is currently underway. Accordingly, PG&E is raising this issue in the opening comments in both proceedings, and requesting that the Commission address it in this proceeding and consider implementation issues that result from any decisions on this issue in Rulemaking 25-09-004.

5. Updates to RA Rules Associated with Large Load Facility Generation Resources

New customers requiring large load interconnections, including data centers, are actively locating in California and PG&E's service territory. The new loads are larger in scale than is typical in the PG&E service area, often exceeding 50 megawatts, and can behave like 'grid infrastructure' rather than typical customer loads. This represents a unique opportunity to

[11] *Id.*, p. 32.

decrease energy costs, drive affordability for existing customers, and, potentially, to ease RA concerns. Given the size of the loads and the location of the data centers in the Greater Bay Area local RA area, PG&E is mindful that the new customers must be incorporated in a way that ensures affordability, reliability, and a clean grid. Because some of these customers are developing generation resources for their large load facilities, these resources could be leveraged to improve reliability and affordability. PG&E recommends including in this proceeding consideration of appropriate updates to the RA rules for large load facility resources to further reliability and affordability goals.

Large load customers, including data centers, are developing generation resources to serve two use cases: (1) as back-up power resources, and (2) as 24/7 generation resources to serve their load while the facility waits for transmission infrastructure to be completed and to be interconnected. In the case of facilities that plan to run generation units 24/7 until the facilities are interconnected, PG&E is working with some of these customers to evaluate the use of cleaner fuels and the potential of these assets to serve as more than back-up power once the facilities are interconnected to the electric system. These generation resources may present an opportunity to reduce costs for existing customers if the resources can be utilized for meeting system and local capacity needs after the facilities are interconnected. For instance, if more data centers locate in the Greater Bay Area local RA area, available excess local RA capacity in the Greater Bay Area local RA area could be strained.[12] This could result in the need to procure new local generation and/or new transmission, which may take years or decades to develop. Generation capacity is also limited by existing rules and conditions. For example, the CAISO limits how much storage can count toward local requirements and the total storage capacity in the Greater Bay Area local

[12] *See* CAISO, 2026 Local Capacity Technical Study Final Report and Study Results, April 30, 2025, p. 2.

RA area already exceeds those limits.[13] Renewable capacity (solar and wind) in the Greater Bay Area local RA area is also limited by qualifying CAISO system deliverability, resource potential, and suitable land. Because many areas will require new transmission facilities to meet the CAISO system deliverability requirement, it could take 10-15 years to develop the necessary generation and transmission facilities to meet local RA requirements.

Given these limitations, it is possible that new natural gas generation could be needed to meet Greater Bay Area local RA area requirements and broader system constraints. If this is the case, it may be more cost-effective to leverage generation facilities that have already been built by large load customers, rather than build additional capacity to serve this load. As this issue continues to develop, PG&E recommends scoping this issue into this proceeding while additional information is compiled on need and potential solutions.

III. COMMENTS ON PRELIMINARY SCHEDULE AND DETERMINATIONS

PG&E does not object to the preliminary schedule and determinations regarding the category of the proceeding or the need for evidentiary hearings as set forth in the OIR. Consistent with its comments above in Section II, however, PG&E requests that the preliminary schedule bifurcate Track 1 issues, with proposals on all Track 1.A issues (i.e., all Track 1 issues other than 7) due January 23, 2026, and Track 1.B proposals on issue 7 (Transactability Issues within the SOD Framework) due at least 30 days after issuance of Energy Division Staff's report on potential transactability issues within the SOD framework.

IV. CONCLUSION

PG&E appreciates the opportunity to file these comments and respectfully requests that the Commission adopt PG&E's recommendations for the reasons discussed herein.

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[13] *Id.*, pp. 29 and 63.

Respectfully submitted,

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