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

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes	R.20-05-003 (Filed May 7, 2020)

OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON RELIABLE AND CLEAN POWER PROCUREMENT PROGRAM STAFF PROPOSAL

[PUBLIC VERSION]

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TABLE OF CONTENTS

TABLE OF CONTENTS

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I. INTRODUCTION

Pursuant to the *Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal* ("ALJ Ruling"), filed April 29, 2025, the *Email Ruling Granting Request for Extension of Time*, filed May 15, 2025, and the *Email Ruling in Response to Motion for Clarification of Alliance for Retail Energy Markets*, filed June 16, 2025 ("E-Mail Ruling"), and in accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Pacific Gas and Electric Company ("PG&E") respectfully submits these opening comments in response to the *Staff Proposal: Reliable and Clean Power Procurement Program* ("Staff Proposal").[1]

In Section II of these opening comments, PG&E provides one recommendation on an item not directly covered by the specific questions in the Staff Proposal but directly related to the implementation and consideration of the Reliable and Clean Power Procurement Program ("RCPPP").[2] PG&E recommends issuance of an interim (i.e., one-time) procurement order or other action to address near-term system reliability needs by 2030 based on an analysis conducted by PG&E. In Section III, PG&E provides its initial responses to the specific questions in the Staff Proposal. Section IV briefly concludes.

[1] The Staff Proposal is attached to the ALJ Ruling as Attachment A.
[2] *See* the ALJ Ruling, p. 4, stating that points related to aspects of the Staff Proposal, but not directly covered in the specific questions set forth in Section 5 of the Staff Proposal, are to be provided at the beginning of filed comments.

II. THE COMMISSION SHOULD ISSUE AN INTERIM (I.E., ONE-TIME) PROCUREMENT ORDER TO ADDRESS NEAR-TERM SYSTEM RELIABILITY NEEDS BY 2030

PG&E recognizes that there are important implementation details that need to be discussed and developed before fully implementing the RCPPP with greenhouse gas ("GHG")-emissions reduction targets and multi-year resource adequacy ("RA") requirements including, among other things, actions to be taken to address procurement deficiencies, integration with the local RA central procurement entity ("CPE") framework, and development of compliance and enforcement tools, etc. This means that the earliest possible date for a multi-year RA program using the slice-of-day ("SOD") framework to be implemented (which PG&E supports) is in October 2027 for the delivery period of 2028-2031. In PG&E's view, this implementation timeline is not capable of providing timely market signals to load serving entities ("LSE") and developers for any necessary procurement needed to meet near-term system reliability needs by 2030 that is incremental to the procurement already planned when LSEs submitted their respective IRP plans just a few years ago.

Accordingly, PG&E recommends that the Commission either: (a) conduct a reliability needs assessment by September 30, 2025, that focuses on the delivery period of 2028-2030 or (b) leverage PG&E's stack analysis as presented below and issue an interim (i.e., one-time) procurement order to serve as a bridge between now and full implementation of the RCPPP or consider other actions to affordably mitigate the identified need. In support of its recommendation, PG&E conducted a stack analysis under the SOD framework using several public sources of information that are published by the Commission and the California Energy Commission ("CEC"). The inputs, assumptions, and methodology used in this stack analysis, and subsequent recommendations, are described in further detail below and have been included in Appendix A attached hereto.

A. PG&E's Stack Analysis to Assess Near-Term System Reliability Needs by 2030

In response to Energy Division staff's request at the workshops, PG&E provides its stack analysis that shows the potential for both insufficient RA supply and insufficient energy storage charging capacity under the SOD framework. In Table 1 below, PG&E summarizes its findings, for the month of September 2030, that show insufficient RA supply, ranging from 776 to 2,210 megawatts ("MW") of net qualifying capacity ("NQC") for Hour Ending ("HE") 15 through 24.[3] PG&E's stack analysis includes 24,304 MW of 4-hour energy storage resources, which is based on the March 2025 - Resource Tracking Data Report, published by the Commission in May 2025. Because energy storage resources can be used in any hour of the month under the SOD framework, PG&E optimized their usage by applying those resources to the peak hour window of HE 18 through 21 then using any remaining capacity available from these energy storage resources evenly across all other hours with a deficiency. Below, column E of Table 1 shows the expected surplus or shortfall in meeting the system RA requirements for the month of September 2030.

Table 1: RA Supply Conditions for September 2030 (MW)

Hour Ending (A)	System RA Requirements (B)	RA Supply (Non-Energy Storage) (C)	RA Supply (Energy Storage) (D)	Surplus / (Shortfall) (E) = (C) + (D) – (B)
15	60,771	56,911	3,084	(776)
16	61,872	55,949	4,733	(1,190)
17	63,553	52,554	8,789	(2,210)
18	64,057	46,414	17,643	0
19	62,423	45,524	16,899	0
20	59,550	45,689	13,861	0
21	57,505	45,712	11,793	0
22	54,036	44,427	7,678	(1,931)
23	52,161	44,190	6,369	(1,602)
24	50,479	44,063	5,126	(1,289)

[3] For simplicity purposes, PG&E is showing HE 15 through 24 in Table 1. Table A.2 in Appendix A includes RA supply conditions for HE 1 through 24.

Because the SOD framework also requires sufficient energy storage charging capacity (i.e., a charging sufficiency test), PG&E's stack analysis also includes this requirement. In Table 2 below, PG&E summarizes its findings, for the month of September 2030, that show insufficient energy storage charging capacity, totaling 64,327 megawatt-hours ("MWh"). Based on the use of 24,304 MW of 4-hour energy storage resources available (line A) to use towards the system RA requirements and assuming an 80 percent round-trip efficiency loss, the total energy storage charging capacity needed is 121,518 MWh (line B). It is estimated, however, that only 57,191 MWh are available (line C). This effectively results in insufficient energy storage charging capacity under the SOD framework for the month of September 2030.

Table 2: Energy Storage Charging Capacity Conditions for September 2030

Line	Description	Quantity
A	4-Hour Energy Storage (MW)	24,304
B	4-Hour Energy Storage (MWh) w/ Roundtrip Efficiency	121,518
C	Total Supply Available to Charge (MWh)	57,191
D	Surplus / (Shortfall)	(64,327)

As mentioned above, based on its stack analysis and the likelihood that the RCPPP could take additional time to finalize certain important details before being fully implemented, PG&E recommends that the Commission issue an interim (i.e., one-time) procurement order to address both insufficient RA supply and insufficient energy storage charging capacity under the SOD framework for the 2030 delivery year or consider other actions to affordably mitigate the identified need. In light of these demonstrated energy sufficiency concerns and absent other actions to affordably mitigate the identified need, PG&E is proposing an interim (i.e., one-time) procurement order limited to zero-carbon[4] ("clean energy") generating resources or co-located energy storage resources shown to have sufficient charging capacity (e.g., sufficiently sized co-located resources). Below, PG&E provides additional details on how this one-time procurement

[4] Please refer to PG&E's response in Section III.H.4 for its recommendation on eligibility for zero-carbon resources.

order could be established, based on the identified shortfalls in Table 1 and Table 2 above, and subsequently allocated out to all Commission-jurisdictional LSEs.

B. PG&E's Methodology for Establishing a One-Time Procurement Order Quantity with an NQC Equivalent Using the SOD Framework

First, to determine the quantity of the proposed one-time procurement order or assess other actions to mitigate the identified need, PG&E considered three portfolios of incremental generating capacity that could be developed to address both the RA supply and energy storage charging capacity shortfalls. The three portfolios considered are based on PG&E's evaluation of the California Independent System Operator Corporation's ("CAISO") interconnection queue for resources available with a 2030 online date, which is primarily made up of solar and wind resources with approximately 51.6 gigawatts ("GW") and 6.4 GW of nameplate capacity available, respectively. Specifically, PG&E considered a portfolio of: (1) incremental solar only, (2) incremental wind only, and (3) a combination of incremental solar and wind. Based on PG&E's analysis, the following amount of nameplate capacity from these resources would need to be added to the supply stack to address both the RA supply and energy storage charging capacity shortfalls found for the month of September 2030: (a) approximately 10.2 GW of incremental solar only, (b) approximately 12.0 GW of incremental wind only, or (c) approximately 10.6 GW of incremental solar and wind (approximately 7.2 GW of solar and 3.4 GW of wind). PG&E recognizes that this one-time procurement order could be challenging given historical build-out rates. Thus, should the Commission's assessment determine the need for new resources, other actions to mitigate the identified need should also be explored outside of this procurement order. See PG&E's response in Section III.H.5 for more details.

Next, PG&E converted the amount of incremental nameplate capacity from the three portfolios considered to an NQC equivalent value using the month of September's 24-hour exceedance profile under the SOD framework. To establish a "capacity factor" metric, PG&E considered various options, including identifying the capacity need: (1) at the peak; (2) at the net peak, or (3) averaged across 24-hours. PG&E proposes the average approach in this procurement order given the significant identified need for energy storage charging capacity, which is better addressed by looking at generation across the entire day. For example, PG&E calculated a 24-hour exceedance level of 30.0 percent for solar for the month of September. This is an average hourly value for all solar technology types.

In Table 3 below, PG&E provides this "capacity factor" metric for solar and wind resources, which is 30.0 percent and 23.3 percent, respectively. Then, PG&E applied the respective "capacity factor" metric for each portfolio considered to determine an NQC equivalent quantity that would serve as the basis for PG&E's recommendation for this procurement order. To be clear, PG&E is not recommending a specific portfolio for its proposed procurement order. Rather, the consideration of three portfolios and their nameplate capacity to NQC equivalent conversion process is intended to provide a reasonableness check for the Commission and stakeholders on PG&E's proposed methodology. In other words, because all three portfolios have similar NQC equivalent quantities, it is reasonable to issue a procurement order of approximately 2,900 MW of NQC equivalent from energy generating resources based on PG&E's methodology or recommend other actions to address the identified need. Further, PG&E's methodology to convert the amount of incremental nameplate capacity from the three portfolios considered to an NQC equivalent value allows for the procurement order to be: (1) technology-neutral, and (2) seamlessly integrate into the SOD framework to minimize any valuation and counting rule uncertainty under the SOD counting rules.

Table 3: NQC Equivalent Values by Each Portfolio Type

Portfolio	**Nameplate Capacity (A)**	**Capacity Factor (B)**	**NQC Equivalent (C) = (A) * (B)**
Solar Only	**10,179**	30.0%	**3,054**
Wind Only	**11,961**	23.3%	**2,787**
Combination	**10,621**	-	**2,958**
Solar	*7,217*	*30.0%*	*2,165*
Wind	*3,404*	*23.3%*	*793*

Average of Portfolios	**-**	**-**	**2,933**

C. Additional Considerations for the Procurement Order

PG&E's stack analysis under the SOD framework and proposed methodology results in a procurement need of roughly 2,900 MW of NQC equivalent capacity from zero-carbon generating resources or co-located energy storage resources shown to have sufficient charging capacity (e.g., sufficiently sized co-located resources) to meet an expected energy storage charging capacity shortfall. In this section, PG&E also provides additional details on LSEs' compliance with the interim (i.e., one-time) procurement order that would need to be considered by the Commission.

- Resource Eligibility: In-development resources considered in PG&E's stack analysis are based on the March 2025 - Resource Tracking Data Report, published by the Commission in May 2025. This includes in-development resources based on "LSE self-reported contracting for projects expected to come online between 2025 and 2028," as measured in September's NQC values.[5] As a result, PG&E recommends that resources (a) contracted for, (b) not included as part of the Commission's Resource Tracking Data Report, (c) and not being used for the procurement orders issued via Decision ("D.") 21-06-035 and D.23-02-040 should be eligible to count towards this interim (i.e., one-time) procurement order. This would effectively establish a "baseline" similar to the baseline established in D.23-02-040. Establishing resource eligibility is critical to ensure that resources procured in response to this proposed procurement order or those issued via D.21-06-035 and D.23-02-040 are not double-counted.
- Measuring Compliance: Similar to the existing compliance and counting rules, PG&E recommends that technology factors for energy generating resources be

[5] *See* the March 2025 - Resource Tracking Data Report, Slide 2, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-march-2025-release.pptx.

based on the simple average of September's 24-hour exceedance profile for each technology class under the SOD framework. PG&E provides indicative numbers in Appendix A based on the latest technology factors and exceedance profiles published by the Commission under the current RA program. This value would be applied to the nameplate capacity to measure whether an LSE has met its allocated share of the procurement order.

- Allocation of the Procurement Order: Given the sense of urgency and the need to bring new resources online in a timely manner, PG&E recommends that the procurement order be allocated on a load-share basis.
- Timing of the Procurement Order: PG&E recommends that the Commission issue the interim (i.e., one-time) procurement order by December 31, 2025, so that project developers can make the necessary adjustments to their development plans, if applicable, and LSEs have sufficient time to bring online the resources needed by 2030.

III. PG&E'S RESPONSE TO SPECIFIC QUESTIONS IN SECTION 5 OF THE STAFF PROPOSAL

A. Reliability Option I vs. Option II

1) Which reliability option (i.e., Option I or Option II) should the CPUC adopt? Please explain the justification for the recommended option in detail.

The Staff Proposal contains two options for the reliability track: Option I and Option II. As outlined in detail below, PG&E has concerns with both Option I and Option II. In response to these concerns, PG&E is filing a comprehensive alternative proposal as a standalone document, separate from these opening comments, and concurrently with this filing. Below, PG&E first explains its concerns applicable to both Option I and Option II before turning to concerns specific to Option I and then concerns specific to Option II.

PG&E's Concern with Option I and Option II: A Secondary Compliance Regime That Uses ELCCs Should Not Be Established.

PG&E's overarching concern with both Option I and Option II is their reliance on two different regimes to determine compliance – SOD for RA program compliance and effective load carrying capacity ("ELCC") for RCPPP compliance. Due to the problems identified below, PG&E recommends the Commission utilize a single set of compliance rules (i.e., SOD) to drive reliability procurement.

First, the use of two separate compliance regimes will result in compliance seams. This potential problem has already been recognized by staff. In comparing the SOD and ELCC paradigms, the Staff Proposal states "both approaches are analytically sound, but optimizing for one approach or the other may yield slightly different procurement outcomes."[6] PG&E amends that the seam created with two compliance regimes would not be limited to "*slightly* different procurement outcomes."[7] To demonstrate this point, PG&E estimated its procurement need under the SOD structure and the marginal ELCC accounting structure based on the indicative numbers in the Staff Proposal. Under the SOD structure, PG&E estimates it would procure [redacted] to meet compliance, and, under the marginal ELCC accounting structure, it would procure [redacted] to meet compliance. Based on the IRP's resource cost estimates, this can be translated into an additional procurement cost of up to approximately $736 million per year for PG&E's bundled service customers alone under the marginal ELCC accounting structure.[8] This demonstrates that procurement to meet one set of compliance requirements compared to the other can be meaningfully different. Further, it is not apparent to PG&E that this additional annual cost from using the marginal ELCC accounting

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[6] Staff Proposal, p. 38.
[7] *Ibid.* (emphasis added).
[8] *See* the 2025 IRP Draft Inputs & Assumptions - Resource Costs, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2025-2026-tpp/resource-cost-workbook--2025-draft-ia-mag.xlsx.

structure will provide significantly greater reliability for its customers over the SOD structure. The use of both SOD and ELCC will result in over-procurement for some and under-procurement for others with different time horizons and programs, collectively increasing costs for everyone through over-procurement or the potential for costly just-in-time procurement to meet near-term RA compliance program needs.

Second, in addition to under- or over-procurement risk, the use of two compliance regimes will increase the administrative burden for everyone. LSEs will have to manage their positions under two paradigms on an indefinite basis. Further, the Commission will be required to complete duplicative loss of load expectation ("LOLE") studies and analysis to develop two sets of requirements (i.e., planning reserve margin ("PRM") and resource counting). Reducing the analytical burden on the Commission could result in increased support for other workstreams that will have growing significance as the Commission looks to achieve California's decarbonization targets (e.g., the future of natural gas facilities, need determinations for complex emerging technologies, targeted location-specific procurement, and greater integration of the IRP and RA proceedings as it relates to issues like resource counting).

For these reasons, a single set of compliance rules should be used to avoid unnecessary costs driven by over-procurement for some LSEs or just-in-time procurement for other LSEs and reduce the administrative burden on LSEs and Commission staff. PG&E recommends the RA program's SOD framework be used as the most suitable set of compliance rules for a programmatic approach to achieving California's reliability targets. SOD offers many benefits that ELCC lacks, while avoiding the known ELCC challenges.

To begin, SOD reduces and potentially eliminates the LSE leaning issue. Because the SOD framework bases LSEs' procurement requirements on LSE-specific loads, SOD incentivizes each LSE to procure a balanced portfolio, thereby reducing leaning. For example, under SOD, if an LSE is sufficiently procured to meet its RA load obligations in all hours except for HE 23 in the month of September, procuring a solar resource will result in no reduction in the LSE's overall procurement obligation and would result in over-procurement in solar generating hours. This means the LSE cannot procure towards a single set of technological types and must procure a balanced portfolio. Conversely, with ELCC, LSEs are *not* required to procure to their LSE-specific load shape. This puts LSEs that procure prudently at the mercy of other LSEs that do not.

To demonstrate this, consider the following illustrative example of two LSEs. LSE #1 could have an open position of 5,000 MW. To meet its open position, LSE #1 could procure its full 5,000 MW obligation with four-hour energy storage – without procuring any energy generating capacity. Meanwhile, LSE #2 could have a balanced portfolio of energy storage and energy generating capacity with no open position. However, in the subsequent ELCC study, because LSE #1's procurement was focused solely on four-hour energy storage, the four-hour energy storage ELCC could drop significantly due to energy insufficiency. In this case, LSE #2 would see the value of its four-hour energy storage resources decrease and may now be required to procure.[9] In this example, LSE #2's new procurement need was induced by the poor procurement decisions from LSE #1 and, thus, LSE #1 is "leaning" on LSE #2 to rectify its suboptimal procurement decisions. This represents an inequitable cost-shift.

Second, SOD better prevents resource technological leaning. With SOD, a resource's sub-technology type and location are considered in its accreditation.[10] This additional granularity credits the procurement of specific resources that perform better relative to their general technology class, ensuring the best resources are procured to address potential reliability shortfalls. Specifically, for solar and wind, in total, there are 15 accreditation values for solar

[9] PG&E recognizes, in this scenario, that the ELCC value of the LSE's energy generating resources should increase. However, the increase may not be proportional to the decrease in the value of the energy storage resources. For example, in comparing the MTR ELCCs to the Staff Proposal indicative marginal ELCCs, in 2028, four-hour energy storage decreased 40 percentage points. Meanwhile, solar only increased by seven percentage points and in-state wind, unintuitively, decreased by four percentage points.

[10] See the 2025 Resource Adequacy and Slice of Day Guide, p. 20, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/guides-and-resources/2025-ra-slice-of-day-filing-guide.pdf

and five accreditation values for wind.[11] In contrast, the mid-term reliability ("MTR") ELCCs are less granular. There is only one ELCC value for solar and three ELCCs for onshore wind.[12] The additional granularity with the SOD structure can be impactful as IRP assumptions indicate that Southern California solar can have up to a 6 percent higher capacity factor relative to Northern California.[13] More granular resource accreditation could be achieved with ELCCs but would result in more LOLE modeling and administrative burden to produce and maintain, especially with the potential use of vintaged ELCCs for any new build requirement.

Third, SOD values are stable and transparent, while ELCCs are volatile and opaque. This volatility makes LSEs' planning and developers' valuation difficult and uncertain. The volatility of ELCCs is reflected in a comparison of the indicative marginal ELCCs from the Staff Proposal and the MTR ELCCs. For example, the MTR ELCCs published in 2023 valued four-hour energy storage at 77 percent (2028) while the Staff Proposal showed a value of 37 percent (2028), representing a reduction of 40 percentage points over a two-year period.

Table 4: Comparison of IRP ELCC Values for 2028

Technology Type	MTR ELCCs (2023)	Staff's Indicative ELCCs (2025)[14]	Delta
4-Hour Battery Storage	77%	37%	(40%)
8-Hour Battery Storage	90%	41%	(49%)
12-Hour Pumped Hydro Storage	93%	41%	(52%)
Solar	9%	16%	7%
In-State Wind	15%	11%	(4%)

[11] See the VER Hourly QC and VER Exceedance Profile tabs from the Master Resource Database, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/mrd-final-2025_05102025v2.xlsx

[12] Seethe Incremental ELCC Study for Mid-Term Reliability Procurement (January 2023 Update), p. 10, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20230210_irp_e3_astrape_updated_incremental_elcc_study.pdf

[13] See Staff's 2025 Draft Inputs and Assumptions, p. 120, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2025_draft_inputs_and_assumptions_doc_20250220.pdf.

[14] Staff Proposal, pp. 24-25.

Offshore Wind	45%	50%	5%

PG&E recognizes there is likely to be a clear rationale for this reduction (e.g., energy insufficiency may be driving some unserved energy events). However, the rationale has not been made clear to LSEs. If declining energy storage ELCCs are the result of a need for more energy generating capacity, it would be more transparent and efficiently and promptly addressed in the SOD framework, given that the SOD requirement for LSEs is to bring charging sufficiency with energy storage. With the ELCC approach, LSEs must wait for an aggregation of LSEs' procurement and a subsequent ELCC study, resulting in a delay in appropriate market signals while also making it more difficult for LSEs to plan and procure prudently for compliance since LSEs cannot anticipate how ELCCs may change. Specifically, LSEs cannot hedge against the risk of changing ELCCs as LSEs do not have insights into the procurement of other LSEs. With regard to developers' valuations, the volatile and opaque nature of ELCCs leads to developers building the valuation risk into off-takers' PPAs, effectively increasing costs for customers.

In summary, two sets of compliance rules should *not* be used. The SOD framework is better suited to a programmatic approach to reliability procurement. Consistent use of the SOD framework will lead to better procurement outcomes, lower costs, and provide consistent market signals. In the two sections below, PG&E turns to its specific concerns with Option I, followed by its specific concerns with Option II.

PG&E's Concerns with Option I: LSEs Must Have Compliance Flexibility in the Mid-Term and No Opportunities to "Game" Compliance.

Regarding Option I, PG&E has two additional concerns. First, Option I requires LSEs to be contracted at 100 percent in T+2. This would result in increased costs and over-procurement. With Option I, because some imports will not be eligible in T+2, prior to CAISO's import allocation rights process, in the prompt year, LSEs will not have the flexibility to potentially meet their procurement requirements in a more affordable manner. This conflicts with the objective in the Staff Proposal to develop a programmatic approach, "enabling market participants to choose the best procurement strategy that matches their resource preferences and risk tolerance."[15] Also, additional over-procurement risk exists in Option I as a result of the interplay with central procurement of local RA. Currently, the local RA program requires contracting at 100 percent in T+2. Therefore, requiring LSEs to also be procured for system RA at 100 percent in T+2 means that any local RA procurement completed by the local RA program CPEs increases the risk that downstream LSEs will be over-procured for system RA in T+2. Further, other uncertainties (e.g., load forecast and load migration) will increase the likelihood of costly over-procurement with a 100 percent contracting requirement at T+2.

Option I would also not have sufficient enforcement rules for LSEs to ensure new resources contracted for in T+2 achieve commercial operations. This could lead to some LSEs manipulating compliance. Specifically, an LSE could sign a contract for a new resource to meet its T+2 requirement by signing a contract with no intention of bringing it to fruition and subsequently meet its RA program requirement by other means. If a large group of LSEs take this approach, there will be insufficient capacity to meet reliability targets in the prompt year. Compliance requirements that lack enforcement are meaningless and create more work and costs than necessary and are subject to manipulation.

PG&E's Concerns with Option II: An Explicit New Build Requirement Should Not Be Implemented.

PG&E's primary concern with Option II is the distinct new build requirement. PG&E is opposed to a new build requirement because: (1) LSEs will be procuring new resources to meet their GHG-emissions reduction goals, making a new build requirement within the reliability paradigm duplicative and unnecessary; (2) a need-based allocation of new build requirements is necessary but cannot be structured in a manner which preserves LSE procurement flexibility; and (3) a new build requirement will be complex and administratively burdensome with the potential to increase costs. PG&E also argues that its alternative proposal is appropriately designed with

[15] Staff Proposal, p. 12.

forward-looking requirements and enforcement mechanisms that would negate the need for a new build requirement.

First, PG&E does not believe a distinct new build requirement within the RCPPP to ensure reliability is necessary. Energy Division staff's analysis shows that GHG-emissions reduction targets are and likely will continue to be binding above reliability requirements.[16] Further, the newly added data center load in the CEC's 2024 IEPR forecast is likely to make GHG-emissions reduction targets more binding. For example, in 2035, load increased by ~20 percent while managed-net load peak increased by ~10 percent relative to the 2023 IEPR forecast, indicating GHG-emissions reduction requirements have increased more significantly relative to reliability requirements.[17] As such, increasing and stringent GHG-emissions reduction targets will drive LSEs to procure the necessary new clean energy resources.

The Commission should not implement a new build requirement or process to order new procurement within the RCPPP to achieve reliability. Instead, the Commission should focus its efforts on developing market signals in its program design to ensure the types of resources that effectively address reliability *and* GHG-emissions reduction targets are built and procured. Therefore, a programmatic approach to reliability and GHG-emissions reduction must be considered together. PG&E believes that the extension of the SOD framework (i.e., multi-year RA requirements) and implementation of a new GHG-emissions reduction mass-based compliance program using an hourly tool (e.g., the Commission's Clean System Power ("CSP")) will send the appropriate signals to LSEs. The granularity of the SOD framework will demonstrate hours of critical reliability need against exceedance values based on historical generation data. Additionally, since a GHG-emissions reduction mass-based program will use an

[16] See Staff's RESOLVE and SERVM Analysis of the 2023 PSP, Slide 20, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/2024-01-12-presentation-summarizing-updated-servm-and-resolve-analysis.pdf

[17] See the CEC's 2024 IEPR Planning Forecast and the CEC's IEPR 2023 Planning Forecast, available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=262289
https://efiling.energy.ca.gov/GetDocument.aspx?tn=257302&DocumentContentId=93164

hourly accounting method, there will be clear incentives for the procurement of resources that effectively decarbonize winter and non-solar hours – the same hours that are currently or will be the hours of greatest reliability risk.[18] PG&E recognizes that it will take time to establish a multi-year RA program and a mass-based GHG-emissions reduction program (with forward compliance showings). These programs together will ensure the right mix of new resources are built. Therefore, PG&E has proposed, as discussed in Section II.A and its response in Section III.H.6, an interim (i.e., one-time) procurement order and set of actions that can serve as guardrails while gathering more stakeholder input on an effective and efficient GHG-emissions reduction framework. A well-considered program should complement multi-year RA requirements to provide confidence that a comprehensive RCPPP can be designed without an explicit and on-going new build requirement within the reliability program.

In addition to being unnecessary, PG&E believes a new build resource requirement will have negative effects on a programmatic approach. PG&E sees three options for structuring a new build resource requirement: (1) the Commission could identify new resource needs in T+3 or T+4 and order procurement on a load-share basis; (2) the Commission could identify new resource needs in T+3 or T+4 and order procurement on a needs-basis. This would mean new resource requirements are allocated based on each LSE's relative share of the system's overall open position. In this scenario, if an LSE meets 100 percent of its reliability obligation in the mid-term, it will not receive a new build requirement; (3) the Commission could identify new resource needs in T+3 or T+4 and order procurement with "new" resources defined as achieving a commercial operations date ("COD") within a 10-year period (i.e., Option II).

PG&E has specific concerns with all three approaches above. First, while the Commission's IRP procurement orders have been successful at putting new steel in the ground, they have also had challenges. To date, MTR procurement orders have been allocated on a load-

[18] See Staff's RESOLVE and SERVM Analysis of the 2023 PSP, Slides 22-23, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/2024-01-12-presentation-summarizing-updated-servm-and-resolve-analysis.pdf

share basis. While a load-share approach has the advantage of being easy to implement quickly, this allocation has had an inequitable impact on LSEs' procurement. This has been acknowledged by the Staff Proposal stating, "the 'order-by-order' approach to procurement also has several limitations, including that it…does not facilitate proactive LSE self-provision of required resource attributes."[19]

Second, due to the structure of the MTR procurement orders, LSEs have experienced increased costs. With the MTR procurement orders, more than 40 LSEs were and are procuring known quantities concurrently, creating a gold-rush sellers' market. PG&E is concerned this would continue to be the case indefinitely with the first two approaches (i.e., load-share-based allocation, need-based allocation). In both structures, new resource needs are identified in the mid-term and subsequently allocated to LSEs at the same time, with the same online dates, via a public Commission decision. While a procurement order approach may be necessary at times – indeed, PG&E is proposing here another procurement order—PG&E does not believe it should be baked into an ongoing programmatic procurement paradigm and implemented indefinitely. Doing so would increase costs for customers at a time when affordability is critical and a salient component of continued electrification and decarbonization efforts.

Third, as described above, implementing a new build resource requirement based on LSEs' individual needs (needs-based allocation) would effectively incent an LSE to be 100 percent procured in the mid-term to avoid a new resource requirement. As highlighted in PG&E's concerns with Option I, this is not reasonable and does not permit LSEs with flexibility to use their own best procurement strategy. In fact, there may be viable reasons for some small portion of procurement to be made in the short-term horizon.

Although the 10-year rolling COD definition for "new" resources within the Staff Proposal may address some of these concerns, PG&E is still concerned that this approach, along with the two others, will add significant administrative burdens and complexity to a program

[19] Staff Proposal, pp. 10-11.

seeking clear market signals. With the MTR procurement orders, there has been a significant amount of administrative burden to monitor compliance. Including, maintaining existing resource baselines (which could become more challenging if repowers become more prevalent – see PG&E's response in Section III.C.4), extension requests, compliance review and waivers, and development of compliance mechanisms for delays outside of the control of LSEs (e.g., bridging resources with distinct categories and requirements, baseline swaps, obligation trading, etc.). Further, as is the case with MTR, a new build resource requirement could result in an LSE simultaneously selling and buying in the market if the LSE's needs or shifting circumstances are not considered (e.g., due to load forecast changes or load migration). Therefore, any program structure that includes a new build resource requirement has already been proven to create significant administrative complexity and burden for LSEs and Commission staff and would be further increased with a rolling 10-year COD baseline as proposed in Option II.

For the reasons stated above, PG&E opposes a new build resource requirement in the RCPPP. New resource development will be driven by the GHG-emissions reduction targets and can be further supported by sufficiently high multi-year RA forward requirements and a penalty structure that permits the Commission to issue procurement orders for specific LSEs with repeated deficiencies.

Because of PG&E's concerns, it does not recommend the adoption of either Option I or Option II. Instead, PG&E proposes an alternative that is easier to implement and will lead to more efficient procurement outcomes because it has a single program's compliance rules and reasonable and feasible forward contracting requirements that minimize reliance on short-term products (without the challenges of a distinct new build requirement), and also incents LSEs to procure a balanced portfolio via the SOD framework. Please refer to PG&E's alternative proposal, which has been submitted concurrently with this filing as a standalone document, for additional details.

2) Currently, Option I and Option II have not explicitly considered imports. How should imports be considered, if at all, in Option I and Option II?

As stated above in PG&E's response in Section III.C.1, PG&E supports the use of the SOD framework to assess system reliability needs on a multi-year forward compliance showing basis. Therefore, PG&E recommends that the existing SOD rules for imports should be used. PG&E notes, generally, that imports will not be eligible to meet multi-year RA requirements, as the CAISO's import allocation rights ("IAR") process is generally done on a prompt year basis.[20] However, PG&E does propose one exception and allow the use of imports for multi-year RA requirements to the extent that an LSE has been allocated a New Use Import Commitment or similarly long-term IAR allocation for the specific resource being used under the CAISO's process. The New Use Import Commitment provision allows LSEs to reserve import capability for RA compliance purposes with multi-year allocations to facilitate long-term contracting.[21] Given that CAISO does allocate some imports beyond the prompt year, it is reasonable for LSEs to use these long-term IAR allocations in T+2 and thereafter, for the duration of the established allocation rights.

3) In what ways should Option I or Option II be modified prior to CPUC adoption? Are there relevant considerations that are currently not captured in both options?

In response to this question, see PG&E's alternative proposal that is being filed concurrently with this filing pursuant to the E-Mail Ruling.

4) How should Option I or Option II incentivize re-powers?

For purposes of responding to this question, PG&E is rephrasing this question as: how should Option I or Option II not disincentive re-powers? As implicitly indicated in the Staff Proposal, PG&E notes that already retired or existing resources that are planning to retire in the future provide reliability value (i.e., capacity and local area attributes), such as gas-powered facilities. These resources could be re-powered or retrofitted with reduced or eliminated GHG

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[20] See CAISO Tariff Section 40.4.6.2.1.
[21] *Ibid*.

emissions profiles (e.g., carbon capture sequestration ("CCS") and provide incremental capacity or provide clean energy. That said, PG&E believes that re-powers, retrofits, or other enhancements that meet the identified reliability or clean energy needs should be eligible for the RCPPP. For example, if the RCPPP includes an explicit new build requirement (which PG&E opposes), a re-powered resource should be considered incremental to the resource baseline (and therefore considered "new") and be eligible.

5) Should demand response count towards RCPPP compliance? If so, should it be included in Option I, Option II, or both?

PG&E supports counting demand response ("DR") resources towards any adopted RCPPP. DR resources presently provide reliability value and are used by LSEs towards their RA program requirements. In D.20-06-031, the Commission revised its limitations for DR resources to prevent an over-reliance on use-limited resources.[22] This decision adopted an 8.3 percent cap on DR resources in an LSE's RA compliance showing in addition to hourly availability requirements. These same rules should be incorporated, without modification, into the RCPPP that relies on multi-year RA requirements using the SOD framework, as PG&E has proposed.

B. Alternate Timelines for Reliability Procurement

6) Is the proposed timeline for reliability procurement reasonable, or are there alternate timelines that should be considered?

The Staff Proposal contains three proposed timelines for reliability assessment and procurement. First, to conduct a preliminary evaluation, perform various calculations, and inform the eventual adoption and implementation of either Option I or Option II, LSEs would file their respective IRP plans (due no earlier than December 1, 2025) and year-ahead RA filings (due October 31, 2025).[23] Second, as part of the Commission's assessment of the ability to meet reliability needs, the Staff Proposal states that Option I and Option II will have multi-year

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[22] D.20-06-031, Conclusion of Law 10, Ordering Paragraph, 19.

[23] *See* Rulemaking 25-06-019, *Order Instituting Rulemaking*, issued July 2, 2025 (stating that IRP plans will be required no earlier than December 1, 2025), available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K276/571276511.PDF.

compliance showings for T+0 through T+4 and indicative showings for T+5 through T+9. Lastly, the Staff Proposal states that the first compliance year (i.e., binding year) would be for the 2030 delivery year. Presumably, this is due to the time needed to fully design and implement the RCPPP and provide sufficient lead-time for LSEs to respond to the program design and take action, as needed.

First, as discussed in Section II above, PG&E recommends that the Commission issue an interim (i.e., one-time) procurement order to address system reliability needs by 2030 or consider other actions to affordably mitigate the identified need. While PG&E has provided a reasonable assessment of reliability conditions through its stack analysis under the SOD framework by using a number of public sources of information, some of the information may need to be updated or supplemented with LSE-specific information that only the Commission has. For example, PG&E is unable to determine how much of the in-development resources are part of the procurement orders issued via D.21-06-035 and D.23-02-040. This information is critical in determining which resources would be eligible for the existing procurement orders or the procurement order recommended in these opening comments. To make a final determination for an interim (i.e., one-time) procurement order, PG&E supports the Staff Proposal suggesting the use of LSEs' upcoming IRP plans to conduct a preliminary evaluation and perform various calculations for a near-term reliability assessment, as needed.

Next, regarding the Commission's ability to assess California's reliability needs and whether the electric grid is well-positioned, PG&E supports a multi-year forward compliance showing to demonstrate sufficient capacity resources have been attained by LSEs so that greater certainty is given that California's near-term reliability needs will be met. However, for the reasons discussed above and in PG&E's concurrent alternative proposal filing, PG&E proposes that the Commission adopt the following:

Table 5: PG&E's Proposed Multi-Year RA Requirements

Year	T+0	T+1	T+2	T+3	T+4	T+5
System RA	100%	90%	80%	70%	70%	DWR Expected to Have Executed LLT Contracts[24]
Local RA	-	100%	100%	50%	-	

PG&E believes that multi-year RA requirements and the proposed percentages in Table 5 for the outer years (T+2 through T+4) best balance: 1) the time needed for new build to come online, 2) uncertainty related to the use of RA imports and its dependency on CAISO's process, 3) potential changes in the load forecast, and 4) uncertainty on the feasibility of the Department of Water Resources' ("DWR") procurement for long lead-time ("LLT") resources. Within its alternative proposal that is being filed concurrently with this filing, PG&E provides a detailed timeline for reliability assessment and procurement for a multi-year RA program using the SOD framework.

Lastly, as mentioned in Section II, because a multi-year RA program would likely not be ready for full implementation until 2027 and with compliance showings focused on the 2028-2030+ delivery years, PG&E recommends that the Commission issue an interim (i.e., one-time) procurement order to serve as a "bridge" for assessing and procuring to meet system reliability needs by 2030, especially in light of recent increases in the load forecast driven by data center load growth in California. This will provide the time needed to develop a multi-year RA program that is intended to provide sufficient lead-time and market signals to LSEs while allowing the Commission to assess reliability needs by 2030 and take the appropriate action needed. Because these reliability needs will be addressed through an interim (i.e., one-time) procurement order, PG&E proposes that the first compliance year (i.e., binding year) for the RCPPP be for the 2031 delivery year.

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[24] PG&E believes it is reasonable for DWR's contracts to be executed in T+5 with attributes subsequently allocated by T+4. This is in accordance with AB 1373 which states that DWR's procurement must have "a construction and development lead time of at least five years."

7) Should compliance filings occur once or twice a year?

In response to this question, see PG&E's alternative proposal that is being filed concurrently with this filing pursuant to the E-Mail Ruling.

8) Should enforcement of contracting sufficiency occur once or twice a year?

In response to this question, see PG&E's alternative proposal that is being filed concurrently with this filing pursuant to the E-Mail Ruling.

9) Should enforcement of online sufficiency occur once or twice a year?

In response to this question, see PG&E's alternative proposal that is being filed concurrently with this filing pursuant to the E-Mail Ruling.

C. To Bound or Not to Bound

10) Should marginal ELCCs be bound? What are advantages or disadvantages to doing so, if any, in addition to those described in Section 3.1.6.4?

See PG&E's response in Section III.C.1 above. In addition, PG&E notes that the need to "freeze" marginal ELCC values for planning and procurement purposes illustrates why ELCCs should not be used.

11) If marginal ELCCs are to be bound, should the degree of bounding differ between Option I and Option II?

See PG&E's response in Section III.C.1 above.

D. Months of Forward Contracting

12) How many months, and which months, should forward contracts include to ensure reliability while minimizing costs if resources can sell to other non-CPUC jurisdictional LSE buyers in other months?

In response to this question, see PG&E's alternative proposal that is being filed concurrently with this filing pursuant to the E-Mail Ruling.

E. Buffer Percentage

13) How much more reliable should the system be compared to the 1-day-in-10-year LOLE? Is a buffer of 2.5% a reasonable value? If not, what is an appropriate percentage value for the buffer?

The Staff Proposal recommends a "reliability buffer" that would be assigned to each LSE to "mitigate development risk and/or other potential causes of insufficient resources."[25] The reliability buffer would be an additional 2.5 percent procurement requirement on top of every LSE's reliability procurement requirement, regardless of their overall portfolio needs. While PG&E believes that individual LSEs should bear responsibility for managing their portfolio needs and hedging against their own project delay risks, the reliability buffer inappropriately prejudges an outcome. For the reasons discussed below, PG&E opposes the reliability buffer proposal and recommends that the Commission refrain from adopting such a mechanism.

As a part of prudent planning, LSEs are responsible for ensuring a proper margin in their procurement planning to anticipate against their own portfolio risks, including delayed procurement. Further, a properly designed penalty structure for the RA program provides the incentives for LSEs to hedge against their own procurement risks. As a result, LSEs that are properly managing their portfolio and project development risks should not be broadly penalized by prejudging the outcome of mismanaging their portfolio and thus, requiring them to pay for additional capacity in advance of any perceived project development delay. This makes the reliability buffer an unnecessary and costly addition to LSEs' procurement requirements.

Further, the reliability requirements are being calibrated to meet a 0.1 LOLE standard, as this has been broadly accepted as the best balance between cost, economic, and social tradeoffs. A universally applied reliability buffer serves two bookends. It will mitigate *all* project development delays experienced by *all* LSEs at best and, at worst, it is a blunt and potentially costly instrument to achieve above a 0.1 LOLE industry standard. With accurate system modeling and forecasting, the PRM setting process that comes out of the 0.1 LOLE study process should continue to be an appropriate standard. Instead of requiring additional costly

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[25] Staff Proposal, p. 18.

procurement for all LSEs that prejudges the outcome of mismanaging one's portfolio, the Commission should strive to improve the accuracy and responsiveness of system modeling and forecasting to better meet the 0.1 LOLE standard.

14) How should the affordability impact of the buffer be weighed against its reliability benefit?

As stated above, PG&E does not see additional benefit from the reliability buffer if an appropriate LOLE/PRM setting is taking place and specific actions are being taken by LSEs to address their own new project development delays. For example, at the system level, the reliability buffer could cost up to $484 million for 2027, assuming only 4-hour energy storage resources were procured.[26] Given current affordability concerns and the historically accepted 0.1 LOLE level, policies aimed at specifically addressing development risks, insufficient resources, and forecast deviations would be much more cost-effective than this system-wide over-procurement mechanism.

15) Should the buffer apply to both Option I and Option II? Why or why not?

See PG&E's response in Sections III.E.13 and III.E.14 above.

16) Should the buffer percentage differ between Option I and Option II? Why or why not?

See PG&E's response in Sections III.E.13 and III.E.14 above.

F. CCR Percentage

17) At what percentage should the CCR be set?

The Staff Proposal proposes the implementation of a Collective Capacity Reserve ("CCR"), ranging from a minimum of 1.5 percent to a maximum of 3 percent of the system-level

[26] To estimate this amount, the Staff Proposal provides an indicative reliability procurement need of 51,212 MW of ELCC for 2027. A 2.5 percent reliability buffer for 2027 is 1,280 MW of ELCC, which equates to 3,460 MW of nameplate capacity from 4-hour energy storage resources based on a marginal ELCC value of 37 percent. As a result, 3,460 MW multiplied by $140/kW-Year equals roughly $484 million. *See* 2025 IRP Draft Inputs & Assumptions - Resource Costs, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2025-2026-tpp/resource-cost-workbook--2025-draft-ia-mag.xlsx.

reliability requirements. The CCR would be allocated to each investor-owned utility ("IOU") on a load share basis with percentages that may be adjusted over time. The Staff Proposal indicates that the CCR is needed to serve as "collective insurance against a variety of events, including RCPPP capacity deficiencies of LSEs (which are unmitigable in real time), large changes in total load forecast, or unexpected retirements." Further, the CCR is intended to provide additional capacity with the expectation that LSE deficiencies may not be known until T+0. While there may be valid reasons for implementing a CCR mechanism as a tool to manage uncertainty, PG&E opposes the current proposed structure and recommends modifications before adoption by the Commission. The CCR mechanism must be designed so that it is used as minimally as possible. Thus, PG&E recommends that the CCR mechanism and its use be evaluated every two years as part of the LOLE study and PRM setting process in the RA proceeding and include the modifications discussed below.

PG&E's recommendation to evaluate the CCR mechanism every two years means that the percentages to set the CCR mechanism would also be set every two years and based on the latest information at that time. PG&E has concerns with broadly establishing percentage levels that are intended to address "large changes in total load forecast, or unexpected retirements," especially if such items do not materialize or are not as applicable in the future. In other words, the lower bound of the CCR percentage level should be set at zero and the upper bound should be set as part of the LOLE/PRM study process.

PG&E also notes that Energy Division will complete an evaluation of whether transactability issues exist under the SOD framework in Q1 2026. The premise underlying the transactability issues is that the requirement of SOD to contract for all 24 hours of a resource's output in a given month can lead to situations in which LSEs are unable to perfectly optimize their portfolios to their load, potentially leading to a capacity margin in excess of the established PRM level. While it is unclear to PG&E if this is indeed the case, that capacity margin could provide for the extra volumes contemplated in the Staff Proposal.

PG&E also recommends that resource eligibility for the CCR mechanism should be broadened to mirror those of the current effective PRM. This modification would allow a broader array of products to be procured for the CCR, enabling more cost-effective procurement because such resources would not necessarily compete against LSEs for RA-eligible resources. In addition to excess RA from the IOUs' portfolios, eligible resources procured and used for the CCR mechanism would include incremental capacity from existing power plants, resources at risk for retirement, incremental energy storage capacity, and firm forward imported energy.[27] Additionally, broadening the CCR category to allow for new or existing resources would allow for procurement flexibility and cost-effective solutions.

Overall, PG&E supports the CCR mechanism with the modifications described above that allow for flexibility in procurement, cost-value analysis in setting the CCR percentage every two years, and broadening the procurement guidelines. These modifications will ensure the risks of short-term reliability needs are appropriately managed against the cost of additional procurement and that procurement is made on an as-needed basis.

18) Is the range of 1.5% to 3% of the initial RPN appropriate? If not, what is an appropriate range?

See PG&E's response in Section III.F.17 above. In addition, PG&E notes that the Commission is expected to conduct its LOLE study and PRM setting process in 2026/2027 as part of the RA proceeding. That process should evaluate the need for and use of a CCR mechanism and its percentage levels based on the information known at that time, including changes in the load forecast or unexpected retirements. This will allow the Commission to make a decision based on the latest information and balance the costs of incremental procurement that it may deem necessary.

19) Should the CCR percentage differ between Option I and Option II? Why or why not?

See PG&E's response in Section III.F.17 above.

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[27] D.21-02-028, pp. 10-12.

G. Incorporating Centrally Procured Resources

20) Which option, as presented in Table 11, is better for incorporating new eligible centrally procured resources into RCPPP? What are additional pros and cons of each option?

The Staff Proposal concludes by raising the question of how best to incorporate centrally procured resources, including those that will be centrally procured by the DWR pursuant to Assembly Bill ("AB") 1373 and D.24-08-064. In doing so, the Staff Proposal provides two options: (A) include those resources from the need determination, with capacity credits later given to LSEs (similar to the existing cost allocation mechanism ("CAM") credit allocations in the RA program), or (B) exclude those resources in the need determination, obviating the need for credits to be later given, because the LSE obligations would already be reduced by a lower overall need determination.[28] Because PG&E's alternative proposal has design elements that mirror the existing RA program, has multi-year RA requirements through T+4 using the SOD framework, and is intended to seamlessly integrate with the timelines established for DWR's procurement authority, PG&E supports Option A above with the understanding that it follows the existing CAM process.

The CAM process was first established by the Commission via D.06-07-029 with the costs and benefits allocated to all customers in the respective IOU territory (including bundled service and departing load customers). Because the Commission and LSEs currently use and understand the CAM process, it is reasonable to use this same process to allocate attributes associated with DWR's procurement authority. This would be the most efficient method and require the least amount of new program design. Similar to the CAM process, PG&E recommends that RA capacity attributes be treated as a load decrement for LSEs to use against their RA compliance obligations as this would obviate the need for a new contracting process.[29]

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[28] The Staff Proposal states that Option B would *include* centrally procured resources from the need determination because LSE obligations would already be *reduced* by a lower need determination. PG&E believes that this may be an inadvertent error because a reduced need determination would be due to an exclusion of the resources.

[29] *See* D.23-12-036, p. 85.

Related to resources centrally procured by DWR, PG&E continues to urge the Commission to develop a mitigation plan in the event that DWR fails to procure the full amounts authorized in D.24-08-064 and reliability is potentially impacted. Specifically, PG&E's alternative proposal calls for DWR's contracts to be executed by T+5 in accordance with AB 1373. If contracts are not executed by then, the Commission must take appropriate action to ensure reliability needs will be met between the T+0 through T+4 timeframe. This may include the procurement of bridging resources by DWR or individual LSEs. DWR's procurement will ultimately have an impact on the amount of procurement that is required by LSEs so the interaction and time needed as a mitigation measure cannot be overlooked in the design of the RCPPP.

H. Approaches to GHG Reduction

1) Should existing IRP and RPS processes be used or modified to achieve the electric sector's GHG emissions reduction goals instead of a new CES framework? If so, why?

The Staff Proposal puts forth a recommendation to build upon the existing renewables portfolio standard ("RPS") program design and processes and develop a clean energy standard ("CES") program aligned with California's GHG-emissions reduction goals. PG&E recognizes the success of the RPS program in significantly spurring the growth of the renewable energy sector. However, PG&E believes a different, more granular programmatic approach and program structure than what has been provided in the Staff Proposal is needed to achieve California's GHG-emissions reduction goals.

PG&E Urges More Time to Develop the GHG-Emissions Reduction Track

The Staff Proposal appears to have a sense of urgency to quickly establish a GHG-emissions reduction program to direct immediate action by LSEs. To do so, the Staff Proposal suggests a preference for an RPS-like program rather than an entirely new program that would require a significant undertaking to create. While this may be true, it is not clear that setting up an RPS-like program would be significantly quicker. It is likely that an RPS-like program will require a similar amount of time, work, and stakeholder engagement as a new program prior to being ready for full implementation. In other words, it is unlikely that even a more straight-forward CES structure can be adopted quickly enough to send market signals to drive LSEs' actions for the first proposed Compliance Period ("CP") of 2028-2030. For example, a significant number of key implementation details remain open for an RPS-like program such as eligible technology types, compliance requirements for out-of-state resources (if eligible), compliance targets, cost containment measures, alternative compliance mechanisms, how to account for dual and competing compliance rules (e.g., banking versus no banking versus limited banking), updating any relevant CEC guidebook, updating CEC processes to verify resource eligibility, setting up software to support zero-emissions credits ("ZEC"), and necessary modifications to the RPS penalty structure to prevent duplicative RPS and GHG-emissions reduction compliance penalties. Importantly, because the proposed CES structure is backwards looking, the first compliance showing would not be until August 2029. This effectively gives the Commission and stakeholders nearly 3-4 years to finalize the implementation details for the proposed CES structure. There is no reason that that same amount of time cannot be spent developing a new program that would be more effective in meeting California's decarbonization goals.

The Commission should take that time (which will likely be less than 3-4 years) to develop a robust GHG-emissions reduction program that includes at least two critical components to help achieve California's decarbonization goals: (1) mass-based compliance requirements and (2) forward compliance showing requirements. These items are discussed in greater detail below.

PG&E believes that the Commission can continue its path towards achieving California's GHG-emissions reduction goals while simultaneously developing such a program. This can be done through an interim (i.e., one-time) procurement order as discussed in Section II above and a clear timeline with key milestones as discussed in Section III.H.6 below. In particular, PG&E's proposed procurement order specifically limits eligibility to zero-carbon generating resources that will ensure progress is being made towards California's goals.

PG&E Urges the Commission to Adopt a GHG Mass-Based Approach for the RCPPP

As described in the Staff Proposal, the GHG-emissions reduction track is intended to ensure LSEs procure towards their share of California's clean energy (SB 1020 and SB 100) and GHG-emissions reduction targets (AB 1279). While related and overlapping, the two sets of legislative requirements are distinct, meaning achieving the targets specified in one will not automatically result in the achievement of the other. Specifically, IRP analysis indicates that the GHG-emissions reduction targets will be "binding" over the clean energy requirements.[30] In other words, GHG-emissions reduction targets are more stringent and will require more new resources to be built. Therefore, given the "binding" nature of GHG-emissions reduction targets, it is critical to ensure the appropriate RCPPP design and market signals are developed to specifically ensure AB 1279 net zero targets are achieved. The most critical difference between a CES structure and a mass-based regime is consideration of the temporal impacts of clean energy generation. Given that a mass-based regime considers the temporal impacts of clean energy generation, the appropriate market signals will be sent to LSEs to decarbonize all hours of the year, resulting in an efficient and durable program that achieves all of California's clean energy *and* GHG-emissions reduction goals. Accordingly, PG&E urges the Commission to adopt a GHG mass-based approach for the RCPPP.

First, the CES structure as proposed by the Staff Proposal does not appropriately consider the seasonal and inter-day generation profiles of clean energy resources. For example, the proposed CES structure may not send the appropriate market signal for LSEs to procure clean energy resources with generation in the winter or nighttime hours such as firm/baseload clean energy resources. To demonstrate, in one possible future, the system could have sufficient capacity to achieve the targeted reliability requirements with a high level of penetration from solar and energy storage resources. However, because the Commission has adopted a CES

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[30] *See* Slides 47-48 of Attachment B: Staff Proposal Reliable and Clean Power Procurement Program https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M565/K140/565140722.PDF.

structure, there are no Commission-mandated hourly tools (e.g., clean system power ("CSP") calculator) used by LSEs for GHG-emissions reduction compliance. In this scenario, LSEs will focus on achieving their CES requirements at least cost (i.e., only contracting with solar resources), without considering other system-level interactions. If enough LSEs limit their procurement to solar resources, there would be significant curtailment, resulting in a failure to collectively meet the prompt year's GHG-emissions reduction target. The CES structure in the Staff Proposal would effectively lead to a failure in achieving aggregate GHG-emissions reduction targets or an inefficient and costly procurement outcome.

The illustrative example provided by PG&E is a feasible reality, especially as curtailment risk increases with the illustrative clean energy targets in the Staff Proposal increasing significantly above today's RPS targets (i.e., 60 percent as compared to the illustrative 87 percent target for 2030 in the Staff Proposal). As such, a more granular approach to clean energy and GHG-emissions reduction planning that considers the seasonal and inter-day generation profiles of clean energy resources is necessary. The CSP calculator (mass-based approach) includes such a framework due to its annual 8,760 hourly look at system conditions,[31] limiting an over-reliance on a single clean energy technology by prohibiting an LSE from achieving additional GHG-emissions reduction through the addition of a new resource if the system is already expected to be curtailing or exporting that clean energy during hours where the added resource is generating.[32]

Therefore, to achieve California's GHG-emissions reduction targets, the CES program design sets strong incentives for a system that has an over-reliance on solar, which may be more costly than alternative options, even if procured with energy storage. For an over-reliance on

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[31] PG&E is open to improvements and simplifications of the Commission's CSP Calculator; however, any simplification should ensure seasonal and inter-day system conditions are sufficiently captured.

[32] *See* Staff's Greenhouse Gas and Criteria Pollutant Accounting Methodology for use in Load-Serving Entity Portfolio Development in 2022 Integrated Resource Plans (July 2022), p. A-4, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/clean-system-power-calculator-documentation.pdf.

solar to be prevented, there must be market signals with the RCPPP design that indicate the need to decarbonize the grid at a more granular level. This is just not the case with the proposed CES structure because all clean energy resources are treated the same – regardless of seasonal differences or inter-day generation profiles.

PG&E also notes the upcoming implementation of SB 1158, which requires GHG-emissions intensity accounting under the CEC's Power Source Disclosure Program. Importantly, the legislative analysis of SB 1158 states that proponents of SB 1158 had significant concerns with an "annual methodology's failure" to accurately capture an LSE's progress towards achieving GHG-emissions reduction targets pursuant to Section 454.52 of the Public Utilities Code and uphold the environmental integrity of the electric sector's contribution to California's clean energy goals. This makes the need for hourly generation and emissions reporting more accurate and transparent. Because SB 1158 directs the Commission to use the annual PSD reports to review the total GHG-emissions intensity of each LSE and assess whether each LSE's procurement plans are demonstrating adequate progress towards achieving the state's clean energy goals, it is critical that the hourly accounting methodology pursuant to SB 1158[33] and the RCPPP design be aligned.

Taken together, reliance on a CES structure alone may not result in a durable GHG-emissions reduction program. LSEs must have compliance requirements that incentivize the procurement of a diverse and complimentary set of resources that consider all hours of the day and all seasons within a year, as is the case with a mass-based approach that utilizes the CSP calculator or another tool that provides for more granularity than an annual metric under the CES structure. This will be especially critical as California seeks to achieve 100 percent clean energy sales and net-zero targets – requiring a precise mix of generation to decarbonize the difficult to address overnight and winter hours.

PG&E Urges the Commission to Adopt Forward Compliance Showings for the GHG-

[33] Public Utilities Code 398.6(g)(1).

Emissions Reduction Target

The Staff Proposal recommends that compliance towards SB 1020, SB 100, and AB 1279 be based on a backwards review of renewable energy credits ("REC") and ZECs by evaluating the MWh credits retired during the compliance period to the total requirement of each LSE. Further, the Staff Proposal includes no forward compliance showing requirement. PG&E is concerned that the lack of a forward compliance showing requirement will incent heavy reliance by LSEs on short-term products, which can be more costly or lead to more deficiencies, especially in times of tight supply conditions. Based on PG&E's observations of recent RPS market trends, it appears that there are emerging issues that can be attributed, in part, to today's structure that lacks a forward compliance showing requirement.

First, a review of the Commission's RPS market price benchmark ("MPB")[34] indicates that short-term RPS prices from 2021 through 2025 have increased by roughly 400 percent (as shown in Table 6 below).[35]

Table 6: Historical Trends of the Commission's Final and Forecasted RPS MPB

Year	2021	2022	2023	2024	2025
Price ($/MWh)	$14	$13	$30	$55	$71
Percentage Change Relative to 2021 MPB		(7%)	114%	293%	407%

The significant increase is especially notable as short-term RPS prices from 2023 through 2025 have remained elevated for a prolonged period, including during the middle of compliance period ("CP") 4 (2021-2024) and the start of CP 5 (2025-2027). While one could expect high

[34] The MPBs are the weighted average price of transactions executed by all Commission-jurisdictional LSEs for portfolio content category 1 renewable energy credits.
[35] RPS MPBs can be found on the Commission's Power Charge Indifference Adjustment webpage with links under the True Up and Forecast Market Price Benchmark Section, available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/power-charge-indifference-adjustment. The 2021-2024 MPBs are considered final values while the 2025 MPB is a forecasted value.

prices at the end of a CP for LSEs attempting to close out a position, high prices that extend from the middle of a CP through the start of another CP deserve scrutiny. Because the elevated prices have been consistent, PG&E believes it could be an indication of a heavy reliance on and demand for short-term RPS products relative to insufficient short-term RPS supply.

To confirm this supposition, PG&E reviewed Commission-jurisdictional LSEs' Renewables Net Short ("RNS") tables as filed in their respective Draft 2024 RPS Procurement Plans.[36] While some LSEs were well-positioned to meet their respective RPS compliance targets through 2027, Draft 2024 RPS Procurement Plans demonstrated that a number of individual LSEs were not on track in meeting their compliance targets and, thus, may need to rely heavily on the short-term RPS market to avoid any compliance deficiency given the limited opportunities for new resource procurement in such a short timeframe. PG&E's findings also match with the Commission's evaluation in D.24-12-035.[37] Therefore, it is reasonable to conclude that the tight RPS market is driven, in part, by a lack of forward compliance showing requirements and an heavy reliance on short-term RPS products to meet compliance. As such, the Commission should establish forward compliance showing requirements in the RCPPP to incentivize prudent forward planning and procurement.

Forward compliance showing requirements provide a better opportunity to identify and correct potential market shortfalls. Given the timelines associated with bringing new resources online, it is necessary to identify potential shortfalls several years prior to the prompt year with time still available for the Commission and stakeholders to act in a cost-effective manner. Because a forward compliance showing would effectively ensure that there is sufficient generation to meet California's clean energy goals, a backwards looking compliance program would be unnecessary and highly duplicative. Accordingly, PG&E recommends that the Commission not institute a backwards looking approach to compliance if a forward compliance

[36] LSEs file RPS plans in the Commission's RPS Docket, Rulemaking 24-01-017. Draft 2024 RPS Plans were filed in Rulemaking 24-01-017 on or around June 30, 2024.
[37] D.24-12-035, pp. 50-51.

showing requirement is an element of the RCPPP design.

2) Should the CPUC adopt the Clean Energy Standard and create Zero-Emission Credit (ZEC) instruments as proposed by Staff with or without modifications?

See PG&E's response in Section III.H.1 above.

3) What considerations should be taken into account to ensure that all RECs and ZECs used for CES compliance would align with how CARB regulates GHG emissions in its Mandatory Reporting Regulation (MRR) and GHG Emissions Inventory?

See PG&E's response in Section III.H.1 above. PG&E also notes that CARB aligns its MRR and GHG Emissions Inventory with Commission practices. This detail should be considered after the finalization of the RCPPP.

4) Which zero-carbon resources should be eligible for the CES?

PG&E interprets this question to be asking which resources should be eligible for the RCPPP that are not already eligible for California's RPS program. As such, PG&E recommends large hydroelectric, nuclear, and the proportional value of GHG-free generation from emerging technologies be eligible to count towards SB 100 and SB 1020 targets in addition to what is eligible for the RPS program. Emerging technologies include partial CCS and thermal resources utilizing partial GHG-free fuels. Recognizing that these technologies currently provide less than 100 percent GHG-free energy, inclusion of only the GHG-free portion of the generation and large hydroelectric and nuclear will allow LSEs to maintain flexibility for least-cost solutions to reach net zero by 2045 and create the appropriate market signals for existing and emerging technologies to continue to mature over time.

As noted in the Commission's Zero-Carbon Technology Assessment Final Report, in order to support California's carbon neutrality policy goals, zero-carbon firm capacity resources may be needed to facilitate cost-effective electric sector decarbonization.[38] However, certain emerging technologies have not yet reached full commercialization. California should create more opportunities for emerging technologies to reach commercial scale, even if not 100 percent GHG-free. Emerging technologies such as thermal utilizing green hydrogen and CCS will take time to become mature and may require additional technological advances. Greening and technological advances should be supported through inclusion rather than discouraged through an exclusion from counting towards clean energy goals.

PG&E also notes that precedent exists for resources with on-site emissions to count towards clean energy requirements, and such resources should be treated consistently based on their attributes. In previous modeling efforts associated with SB 100, resources with some on-site emission (e.g., solar thermal) were permitted to count towards the SB 100 modeling constraints due to their status as RPS-eligible resources. Generation from emerging technologies with some on-site emissions should not be fully counted but should be treated consistently and be evaluated based on their attributes.

Moreover, the Commission's GHG-emissions reduction targets are based on CARB's 2022 Scoping Plan, which represents California's cost-effective plan to achieving net-zero emissions as soon as possible. GHG modeling considers the proportional values of GHG-free generation to meet its constraints, and the RCPPP should follow a similar paradigm to avoid a more stringent constraint not aligned with GHG-targets from CARB's 2022 Scoping Plan. Including the proportional values of GHG-free generation from emerging technologies would put California on a more cost-effective path to decarbonization. As a result, allowing the

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[38] *See* the Commission's Zero-Carbon Technology Assessment Final Report, p. 10, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/cpuc-irp-zero-carbon-technology-assessment.pdf.

proportional values of partial CCS and other emerging technologies to count towards California's clean energy goals will create the correct market signals for emerging technologies and maintain flexibility for least-cost solutions to reach net zero by 2045.

5) Are there alternative approaches to GHG reductions that should be considered and why?

In D.24-02-047, the Commission adopted a 25 million metric ton ("MMT") GHG target for the electric sector by 2035. In doing so, the Commission also adopted a 30 MMT GHG target by 2030. These GHG target amounts were lowered from the targets adopted via D.22-02-004 that established 38 MMT and 30 MMT GHG targets by 2030 and 2035, respectively. PG&E has significant concerns on the feasibility and cost implications of achieving a 30 MMT GHG target by 2030, especially given 1) the forecasted amount of data center load growth by the end of the decade and 2) recent changes in federal law impacting the availability of the investment tax credit ("ITC") to some clean energy technologies. The latest IEPR load forecast includes approximately 2.3 GW of data center load in California. This translates to roughly 20 TWh of incremental energy per year. Because data center loads are generally flat across the day, this would put significant pressure on the amount of additional procurement needed by 2030 that was not previously considered as part of D.24-02-047. To that end, PG&E appreciates the Commission posing this question to stakeholders and provides alternatives that should be considered.

First, PG&E highlights the LSE procurement challenges submitted in the record of this proceeding thus far.[39] The record indicates there may be a need for procurement flexibility, especially given the significant amount of data center growth forecasted by 2030. The volume of data center load was previously not considered when the Commission issued D.22-02-040 and D.24-02-047. The Commission has already acknowledged that LSEs are facing a resource scarce competitive market environment due to the lingering effects of the COVID-19 pandemic,

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[39] *Southern California Edison Company's (U 338-E) and Pacific Gas and Electric Company's (U 39-E) Joint Expedited Petition for Modification of Decision 21-06-035, dated Aug.9, 2023.*

global supply chain constraints, and interconnection queue delays. Moreover, tariffs impacting the import of materials needed to develop new clean energy resources and federal policy on tax credits are making an impact on project valuation and costs that are ultimately paid for by customers. In light of these issues, PG&E recommends that the Commission adjust the 2030 GHG target to 38 MMT. A 38 MMT GHG target by 2030 better reflects market realities and would be more feasible for LSEs to achieve. Importantly, the 38 MMT by 2030 is aligned with CARB's Scoping Plan, which established a 30-38 MMT target range by 2030. PG&E believes that this would balance LSE procurement and market feasibility and customer affordability. For the time being, however, the Commission should continue anchoring to a 25-30 MMT target range by 2035 and monitor LSEs' progress so that LSEs have direction to move towards.

Next, Section 399.15(c)-(e) of the Public Utilities Code provides that the Commission may establish cost containment measures for an electrical corporation stating that the Commission "shall establish a limitation for each electrical corporation on the procurement expenditures for all eligible renewable energy resources used to comply with the renewables portfolio standard. This limitation shall be set at a level that prevents disproportionate rate impacts." While cost containment measures to meet the RPS compliance targets have not been a policy priority, the near-term concerns on affordable electric rates are changing that. Further, policy at the federal level is having an adverse impact on clean energy development that will drive up costs that are ultimately paid for by all Californians. PG&E also notes that CAISO's interconnection queue is primarily made up of solar plus energy storage resources even though baseload resources may be more cost-effective in meeting GHG-emissions reduction goals, especially given the flat profile of data center load.[40] PG&E believes that cost containment measures with a focus on customer affordability are ripe for consideration by the Commission and should remain a priority for all stakeholders involved, especially in the on-going development of the RCPPP and long-term planning and procurement process for 2030 and

[40] For example, PG&E estimates that it would require 5 to 8 times (in total nameplate capacity) more of solar plus energy storage to meet the equivalent of 1 MW of a baseload resource.

beyond.

6) **Should the CPUC further develop a GHG reduction approach through a certain forum (e.g., workshops)? How could guardrails be implemented so that LSEs continue to procure toward future GHG targets while gathering more stakeholder input on an effective and efficient GHG framework?**

As mentioned above, PG&E recommends further development of a mass-based GHG-emissions reduction framework with forward compliance showing requirements. The Commission can develop an effective and durable program with this structure, while maintaining a trajectory of procurement to meet California's 2030 and 2035 decarbonization goals. To accomplish this goal, PG&E proposes that the Commission adopt a mass-based GHG-emissions reduction approach and conduct its further development through a series of workshops. This is a similar approach to what was taken for the SOD framework. Specifically, in 2021, the Commission decided on the direction for a new RA program (SOD) and stakeholders conducted a series of workshops and presented proposals over the course of 2-3 years prior to fully implementing the SOD framework. This approach has proven to be effective by leveraging diverse perspectives and input.

At the conclusion of these workshops, like the SOD stakeholder process, an identified party or parties would prepare and submit a workshop report that provides the final consensus framework and identifies consensus and non-consensus items and parties would be given an opportunity to comment. Within 30 days after the effective date of a final decision on the direction of developing a mass-based GHG-emissions reduction framework in this proceeding, parties should reach agreement and inform the Commission (with service to the service list) of the following:

(1) The date for the first workshop and placeholder dates for at least two subsequent workshops;

(2) The scope of issues for each workshop;

(3) Identified part(ies) to facilitate each workshop; and

(4) Identified part(ies) to prepare and submit the Workshop Report to the Commission.[41]

Additionally, as described above, PG&E's recommendation for an interim (i.e., one-time) procurement order can serve as a guardrail while gathering more stakeholder input on an effective and efficient GHG-emissions reduction framework. Further, PG&E recommends setting a 38 MMT target by 2030 and deciding on a 2035 target between 25-30 MMT prior to the end of 2026 or beginning of 2027, when PG&E estimates that a final GHG-emissions reduction framework can be adopted. Affirming the 38 MMT by 2030 and 25-30 MMT by 2035 now will ensure that LSEs have the proper signals needed to continue procuring clean energy resources while a GHG-emissions reduction framework is developed by the Commission and stakeholders.

IV. CONCLUSION

PG&E appreciates the opportunity to provide these opening comments on the Staff Proposal and recommends the adoption of its proposals herein. PG&E looks forward to working with the Commission and stakeholders on the development of the RCPPP and other matters relevant to long-term planning and procurement for the electric grid.

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[41] This process mirrors the process previously adopted for SOD. D.21-07-014, pp. 39-41.

Respectfully Submitted,

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Dated: July 15, 2025

Appendix A – PG&E's Stack Analysis

PG&E has performed an analysis showing the potential for both insufficient RA supply and insufficient energy storage charging capacity under the SOD framework, assuming a 21 percent PRM for the month of September 2030.[42] The tables below show the RA supply available by technology type and total RA supply conditions, including the placement of energy storage resources for HE 1 through 24. PG&E's stack analysis includes 24,304 MW of 4-hour energy storage resources, which is based on the March 2025 - Resource Tracking Data Report, published by the Commission in May 2025. Because energy storage resources can be used in any hour of the month under the SOD framework, PG&E optimized their usage by applying those resources to the peak hour window of HE 18 through 21 and then using any remaining capacity available from these energy storage resources evenly across all other hours with a deficiency. Below, column E of Table A.2 shows the expected surplus or shortfall in meeting the system RA requirements for the month of September 2030.

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[42] D.25-06-048, p. 21 (indicating that Energy Division's LOLE study results show the need for a 21 percent PRM to meet the LOLE reliability standard for the 2026 and 2027 RA compliance years).

Table A.1: Non-Energy Storage RA Supply by Technology Type

HE	24/7	Solar	Wind	Imports	Other
1	34,313	-	3,236	6,031	-
2	34,313	-	3,095	6,013	-
3	34,313	-	2,890	6,014	-
4	34,313	-	2,490	6,014	-
5	34,313	-	2,260	5,979	-
6	34,313	-	2,154	5,983	-
7	34,313	3,772	1,846	6,137	528
8	34,313	10,437	1,619	6,430	528
9	34,313	12,920	1,460	6,488	528
10	34,313	13,775	1,383	6,530	528
11	34,313	14,013	1,344	6,486	528
12	34,313	14,021	1,342	6,470	528
13	34,313	13,965	1,462	6,485	528
14	34,313	13,835	1,621	6,475	528
15	34,313	13,422	1,917	6,543	717
16	34,313	12,132	2,232	6,555	717
17	34,313	7,523	2,478	6,359	1,881
18	34,313	1,253	2,817	6,150	1,881
19	34,313	4	3,192	6,134	1,881
20	34,313	-	3,364	6,131	1,881
21	34,313	-	3,396	6,121	1,881
22	34,313	-	3,304	6,093	717
23	34,313	-	3,280	6,069	528
24	34,313	-	3,192	6,031	528

Table A.2: RA Supply Conditions for September 2030 (MW)

HE (A)	System RA Requirements (B)	RA Supply (Non-Energy Storage) (C)	RA Supply (Energy Storage) (D)	Surplus / (Shortfall) (E) = (C) + (D) – (B)
1	45,132	43,581	1,239	(312)
2	41,317	43,421	0	2,105
3	38,754	43,218	0	4,464
4	37,619	42,818	0	5,199
5	38,840	42,553	0	3,714
6	42,280	42,451	0	172
7	45,768	46,596	0	827
8	47,852	53,327	0	5,475
9	48,765	55,710	0	6,944
10	48,471	56,530	0	8,058
11	48,413	56,683	0	8,270
12	49,623	56,675	0	7,051
13	52,561	56,753	0	4,192
14	56,051	56,772	0	721
15	60,771	56,911	3,084	(776)
16	61,872	55,949	4,733	(1,190)
17	63,553	52,554	8,789	(2,210)
18	64,057	46,414	17,643	0
19	62,423	45,524	16,899	0
20	59,550	45,689	13,861	0
21	57,505	45,712	11,793	0
22	54,036	44,427	7,678	(1,931)
23	52,161	44,190	6,369	(1,602)

24	50,479	44,063	5,126	(1,289)

Description of Appendix Tables A.1-2 and Key Assumptions

Table A.1 is derived from the Commission's RA 2025 Master Resource Database ("MRD") published in March 2025 with the removal of the once-through-cooling ("OTC") resources and the removal of the Intermountain resources, aligning with the IRP's assumption that these resources will retire in 2026.[43] In addition to the Commission's RA 2025 MRD, in-development resources were added based on the IRP proceeding's March 2025 - Resource Tracking Data Report based on LSEs' self-reported contracting for projects expected to come online between 2025 and 2028 and applied the applicable technology factor for the month of September.[44] Regarding the use of imports, PG&E's analysis includes all resource-specific imports or pseudo-tied and dynamically scheduled resources as part of the supply stack and does not include any non-resource-specific imports, consistent with Energy Division's LOLE study process. Use-limited resources from the Commission's RA 2025 MRD and demand response resources are included in the "Other" column with demand response resources in HE 17 through 21, which are the identified availability assessment hours from CAISO's Final Availability Assessment Hours Study.[45] Finally, Diablo Canyon Power Plant Units 1 and 2 are excluded, consistent with statutory requirements.

In Table A.2, column B is the amount of managed load forecasted for the "worst day" for the month of September 2030, derived from the CEC's 2024 IEPR forecast (March 2025

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[43] *See* 2025 MRD (published March 2025), available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/mrd-final-2025_03142025_ver1.xlsx.
[44] *See* March 2025 - Resource Tracking Data Report, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-march-2025-release.pptx.
[45] *See* PG&E, SCE and SDG&E's 2025-2027 Demand Response Totals, available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials; *See* CAISO's Final Flexible Capacity Needs Assessment for 2026, p. 35, available at: https://stakeholdercenter.caiso.com/InitiativeDocuments/Flexible-Capacity-Needs-Assessment-Final-2026.pdf.

Update).[46] Column B also includes the application of a 21 percent PRM, consistent with Energy Division's latest LOLE Study results from Rulemaking 23-10-011.[47] Column C is the total RA supply of non-energy storage resources from Table A.1. Column D includes all energy storage and hybrid resources from the Commission's RA 2025 MRD and the March 2025 - Resource Tracking Data Report based on LSEs' self-reported contracting for projects expected to come online between 2025 and 2028. All energy storage and hybrid resources are modeled at a 4-hour duration with 80 percent round-trip efficiency. Because these resources can be used in any hour of the month under the SOD framework, PG&E optimized their usage by applying those resources to the peak hour window of HE 18 through 21 then using any remaining capacity available from these energy storage resources evenly across all other hours with a deficiency. Conservatively, PG&E notes that it is treating all hybrid resources similarly to stand-alone energy storage as part of the energy storage charging capacity sufficiency check. Column E represents the calculated hourly RA supply on the system, above the expected need after applying a 21 percent PRM to the forecasted load.

Indicative Values for the One-Time Procurement Order Using the SOD Framework

To establish a "capacity factor" metric, PG&E considered various options, including identifying the capacity need: (1) at the peak; (2) at the net peak, or (3) averaged across 24-hours. PG&E proposes the average approach in this procurement order given the identified need for energy storage charging capacity, which is better addressed by looking at generation across the entire day. For example, PG&E calculated a 24-hour exceedance level of 30.0 percent for solar resources in September, as this is the average hourly value for all solar technology types. Below in Table A.3, PG&E provides indicative numbers based on the latest technology factors

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46 *See* CED 2024 Hourly Forecast – CAISO – Planning Scenario – Correction 32025, available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=262289&DocumentContentId=98796.

47 *See* Rulemaking 23-10-011, *Administrative Law Judge's Ruling on Energy Division's Hour Offset Workshop Slides and Load Migration Update*, filed February 25, 2025, Appendix A, Slide 2 (stating that Energy Division revises their proposal to 21% in summer months (extending June through October) and 20% in off-peak months (November through May)), available at: https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=557607541.

and exceedance profiles published by the Commission under the current RA program.

Table A.3: Indicative Values by Technology Type

Solar (CA)	Wind (CA)	Hydroelectric	Bioenergy	Geothermal	4-Hour Co-Located
30.0%	23.3%	70.0%	93.0%	91.0%	16.7%