OCTOBER FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes.	R.25-06-019

MARIN CLEAN ENERGY'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON ELECTRICITY PORTFOLIOS FOR 2026-2027 TRANSMISSION PLANNING PROCESS AND NEED FOR ADDITIONAL RELIABILITY PROCUREMENT

Sabrinna Soldavini
Vice President of Policy
MARIN CLEAN ENERGY
1125 Tamalpais Ave
San Rafael, CA 94901
Telephone: (415) 464-6670
Email: ssoldavini@mcecleanenergy.org

October 31, 2025

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Marin Clean Energy ("MCE")[1] hereby submits these reply comments pursuant to the

I. INTRODUCTION

MCE appreciates the opportunity to respond to the Ruling and Parties' Opening Comments on questions related to the procurement need analysis and recommendations. In summary, MCE recommends:

- The Commission find that another procurement order is not needed at this time. Rather than issue an ad hoc procurement order that is expected to exacerbate market challenges and the affordability crisis, the Commission should prioritize adoption of the Reliable and Clean Power Procurement Program ("RCPPP") – a more stable and predictable regulatory procurement framework that will better allow LSEs to plan ahead and minimize policy (and cost) shocks; and

[1] MCE, California's first community choice aggregator ("CCA"), is a not-for-profit public agency that began service in 2010 with the goals of providing cleaner power at stable rates to its customers, reducing greenhouse emissions, and investing in energy programs that support communities' energy needs. MCE is a load-serving entity ("LSE") providing electricity generation services to more than 1.8 million people in 38 member communities across four Bay Area counties.

- If the Commission rejects MCE's recommendation to not issue an ad hoc procurement order, the Commission should:
    - Carefully consider the full impacts of any such action on the market and ratepayers by studying and publishing the expected fiscal impacts of issuing another ad hoc procurement order before issuance; and
    - Allocate procurement need to LSE's based on individual, and specific, LSE need as opposed to a pro-rata share of the managed peak, to minimize the subsidization of reliability need between LSEs and their customers.

II. COMMENTS RELATED TO THE PROCUREMENT NEED ANALYSIS AND RECOMMENDATIONS

A. The Commission Should Find that Another Procurement Order is Not Needed at This Time, and Should Instead Focus on the Development and Implementation of RCPPP

In Opening comments,[2] in response to the Ruling asking "is another procurement order needed"[3] several parties expressed skepticism as it relates to the *need* for another procurement order at this time, scrutinizing the level and timing of procurement proposed to be ordered – often due to uncertainties in the load forecast the procurement order would be based on, [4] and/or expressing a preference for or need to focus on the development and adoption of the RCPPP.[5]

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[2] All references herein to party Opening Comments are to the Opening Comments filed in this Rulemaking, R.25-06-019, on or about October 22, 2025

[3] *Administrative Law Judge's Ruling Seeking Comments on Electricity Portfolios for 2026-2027 Transmission Planning Process and Need for Additional Reliability Procurement*, Rulemaking (R.) 25-06-019 (Sept. 30, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M582/K082/582082526.PDF.

[4] *See* California Community Choice Association ("CalCCA") Opening Comments at 4-5; California Coalition of Large Energy Users ("CLEU") Opening Comments at 14 and 26; Alliance for Retail Energy Markets ("AReM") Opening Comments at 7; San Diego Electric & Gas ("SDG&E") Opening Comments at 9; Shell Energy North America ("Shell Energy") Opening Comments at 15; Public Advocates Office at the California Public Utilities Commission ("Cal Advocates") at 7.

[5] *See* Southern California Edison ("SCE") Opening Comments at 15; Shell Energy Opening Comments at 2; Western Power Trading Forum ("WPTF") Opening Comments at 2.

MCE shares this skepticism and asserts that ad hoc procurement orders such as those proposed by the Ruling are not the only, nor the most effective or appropriate mechanism to bring resources online to support the state's reliability needs. Accordingly, MCE recommends that the Commission find that another procurement order is *not* needed at this time. Rather than issue another ad hoc procurement order that will serve as a volatile policy shock to the market, increase costs, and further jeopardize affordability for ratepayers, MCE urges the Commission to instead prioritize the development of RCPPP. If designed appropriately, RCPPP will create a stable and predictable regulatory framework for procurement that will allow LSEs to plan ahead to meet their customers' reliability needs while optimizing their portfolio, minimizing costs, and mitigating ratepayer affordability impacts.

a. A Need for Additional Procurement in the State Does Not Equate to the need for Another Commission Issued Procurement Order

It is important to distinguish the need for procurement from the need for a procurement *order* from the Commission. MCE does not in these comments dispute that the Commission's analysis demonstrates the need for additional procurement to meet California's reliability needs in the 2028-2032 timeframe, ***IF*** all of its assumptions are correct and the full amount of projected load growth in the 2024 IEPR materializes. Accordingly, MCE also does not dispute that some (or most) LSEs would need to procure resources to serve said load. However, as noted above and in Party comments, there is a high probability that the load forecast and therefore the associated need is overstated. And critically, as CalCCA accurately points out, the "need for procurement is not synonymous with a need for a procurement order,"[6] meaning that even if there is a need for procurement generally throughout the state – there is not inherently a need for the Commission to

[6] CalCCA Opening Comments at 25.

prescribe ***how*** this procurement is done by urgently issuing an ad hoc procurement order to all LSEs. MCE urges the Commission to recognize this fact.

A Commission issued ad hoc procurement order is not the only, most appropriate, or most cost effective mechanism to drive reliability procurement. The need for procurement broadly cannot be taken as evidence that the Commission *must* order procurement from all LSEs with strict timing and compliance requirements as proposed in the Ruling.

As stated by CalCCA, LSEs, including MCE and other CCAs, are actively procuring to bring new resources online and meet our customers' reliability needs.[7] Indeed, MCE was created to provide clean, affordable, and reliable power for our member communities. MCE remains committed to procuring to meet the reliability needs of the communities we serve and is committed to doing so absent an ad hoc procurement order that, as past experience and economic principles suggest, is expected to lead to adverse market impacts for LSEs and increased costs for customers. Accordingly, MCE recommends the Commission not issue an ad hoc procurement order at this time.

b. Ad-hoc procurement orders cause market disruptions and jeopardize affordability for customers

MCE agrees with Parties who highlight the risks of market disruptions and increased costs that will be caused by issuing another ad hoc procurement order. Given the current barriers facing LSEs in bringing new resources online, ad hoc procurement orders such as the one proposed in the Ruling serve as volatile policy shocks that can lead to significant market disruptions. These market disruptions are likely to lead to higher costs of procurement and compliance for LSEs, and ultimately these higher costs will be paid by consumers in the form of higher electricity rates.

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[7] *Id*.

As SCE points out, "[r]ecent procurement cycles have demonstrated that when the Commission issues orders with aggressive timelines, developers respond by raising offer prices to account for increased risks related to interconnection schedule, supply chain and engineering procurement construction constraints, and accelerated project permitting and development."[8] MCE agrees, noting that ad hoc procurement orders send a clear market signal to developers that LSEs must procure a set amount of resources by a given deadline or face economic & reputational penalties. This increases demand for specific resources that meet the requirements of the procurement order and shifts market power to sellers who respond by increasing prices. MCE agrees with other LSEs that in a sellers' market, sellers also try to pass the risk related to online times onto LSEs by requiring more lenient contractual terms and conditions and/or price that risk into the contract, both of which can result in increased costs for customers.[9] LSEs would be in a better position to negotiate prices and contractual terms that are favorable to their ratepayers in the absence of a procurement order with prescriptive requirements.

MCE further supports assertions by Parties that point out how prior procurement orders, similar to the one proposed in the Ruling, have led to significant market disruptions SDG&E recommends the Commission "avoid the conditions that led to large increase in Resource Adequacy ("RA") prices", including Mid Term Reliability ("MTR") procurement orders that "very likely contributed to RA scarcity pricing in 2023-2024, which was then reflected in the Market Price Benchmarks and increased customer rate volatility."[10] Similarly, SCE notes "the market

8 SCE Opening Comments at 15.

9 *See* Pacific Gas & Electric Company ("PG&E") Opening Comments, at 16; SCE Opening Comments, at 15.

10 SDG&E Opening Comments, at 11.

responded to the MTR procurement orders with significant increases in bid prices for battery energy storage systems."[11]

The Commission has also recently acknowledged the high prices that LSEs were paying to comply with MTR orders in its Decision adopting SCE's Petition for Modification of Decisions (D.) 23-02-040 and D.24-02-047.[12] By conducting analysis of semi-annual procurement data submitted for MTR compliance, the Commission determined that "[b]ridge contracts are among the most expensive contracts entered into by any LSE on a per-MWh and per-kW-month basis."[13] This is a clear piece of evidence indicating the type of market volatility and higher costs resulting ad hoc procurement orders. MCE, as an LSE who has consistently prioritized compliance with prior procurement orders and RA requirements, has experienced the impact of these disruptions firsthand in its procurement activities. While ad hoc procurement orders may have helped incentivize bringing new resources online in a shorter timeframe, they have likely done so at the expense of higher prices for ratepayers. As discussed in Section B below, the Commission should carefully consider and analyze this tradeoff.

MCE agrees with other Parties who expressed reasonable skepticism about viable projects in the interconnection queue that would come online at currently stated dates to meet near term compliance deadlines given existing challenges.[14] The existence of projects in the CAISO queue does not automatically mean that these are viable projects, nor that they are available for reasonable or prudent prices. Supply chain risk and federal policy uncertainty, along with interconnection queue issues, will further compromise online times, meaning that not only will resources

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11 SCE Opening Comments, at 15.

12 D.25-09-007 at 20.

13 *Id* at 20.

14 *See* PG&E Opening Comments, at 16; CalCCA Opening Comments at 35.

potentially not come online in time, but also that LSEs are then forced into long term, expensive contracts with subpar projects – impacting affordability for years to come.

For these reasons, and amidst the backdrop of a growing affordability crisis, MCE is broadly opposed to the issuance of any ad hoc procurement orders. MCE recommends the Commission find that another procurement order is not needed at this time, and further recommends the Commission urgently transition away from the current paradigm of adopting ad hoc procurement orders that introduce unnecessary policy shocks and prioritize the adoption of a stable, predictable, forward-looking procurement program through the RCPPP.

B. Any Future Procurement Obligations Should be Analyzed through the Lens of Affordability. The Commission Should Study and Publish the Cost and Affordability Impacts of Past and Future Procurement Orders.

While MCE is opposed to the use of ad hoc procurement orders, to the extent that the Commission determines there is a need for one, MCE urges the Commission to carefully consider the market impacts and the resulting impacts to ratepayer affordability. As CLEU notes, the "Ruling lacks an analysis or even a discussion of ratepayer costs associated with 6,000 MW of "perfect" capacity, and ignores the observed phenomenon that, the nearer term the procurement, the fewer number of resources that will be able to meet these timelines, creating a strong sellers' market."[15]

As described above, any additionally mandated short-term procurement will force LSEs to procure in, and likely exacerbate, tight market conditions leading to increased costs that ultimately get passed through to their ratepayers. Therefore, ***any*** incremental procurement orders should be approached with extreme caution and careful consideration of its affordability impacts. MCE strongly supports the notion that the Commission must consider ratepayer impacts of incremental

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[15] CLEU Opening Comments at 21.

procurement orders and urges the Commission to analyze and publish the impacts of past ad hoc procurement orders (i.e. MTR Decisions ("D.") D.21-065-035, and D.23-02-040) *and* the estimated impacts of the procurement order proposed by the Ruling. Such transparent analysis is necessary to help the Commission and Parties understand the full impact and reasonableness of procurement mandates.

C. Any Future Procurement Obligations Should be Allocated Based on LSE Specific Need

The Ruling seeks Party comment on how, if issued, a procurement order should be allocated amongst LSEs. Though understanding that the Ruling proposed to use the allocation methodology from previous procurement orders, likely for simplicity purposes, MCE shares the concerns of Parties who point out that procurement obligations allocated based on a proportional share of total system need may result in over-procurement for certain entities. Ultimately, this leads to unnecessary and unequitable cost shifting amongst LSEs. For example, SDG&E states that if the order extends to 2032, the Commission should adopt individual year allocators "to ensure that LSEs with load that is growing more slowly are not subsidizing LSEs whose load is growing more aggressively,"[16] MCE agrees that the current managed peak load share allocation methodology based on a static number, which does not account for projected load growth by LSE service area can lead to inequitable outcomes for LSEs whose service areas may not experience significant load growth in the future. Essentially, the proposed methodology socializes the procurement costs of meeting the reliability needs of new (and uncertain) load onto all LSEs, as it does not factor in LSE specific need. Customers in service areas with limited load growth should not be expected to subsidize the reliability needs of those LSEs that are growing faster.

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[16] SDG&E Opening Comments at 19.

To avoid cost shifts amongst LSEs and their customers, MCE recommends that any procurement order be allocated based on an LSE's specific need. Procurement obligations should consider the principles of cost causation and individual LSEs' prior actions and future reliability needs and be allocated based on where new load is expected to materialize.

III. CONCLUSION

MCE thanks the Commission for its consideration of these comments. For the reasons set forth above, MCE recommends:

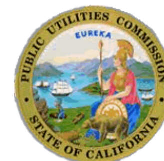
- The Commission find that another procurement order is not needed at this time. Rather than issue an ad hoc procurement order that is expected to exacerbate market challenges and the affordability crisis, the Commission should prioritize adoption of the Reliable and Clean Power Procurement Program ("RCPPP") – a more stable and predictable regulatory procurement framework that will better allow LSEs to plan ahead and minimize policy (and cost) shocks; and
- If the Commission rejects MCE's recommendation to not issue an ad hoc procurement order, the Commission should:
    - Carefully consider the full impacts of any such action on the market and ratepayers by studying and publishing the expected fiscal impacts of issuing another ad hoc procurement order before issuance; and
    - Allocate procurement need to LSE's based on individual, and specific, LSE need as opposed to a pro-rata share of the managed peak, to minimize the subsidization of reliability need between LSEs and their customers.

Respectfully submitted,

Dated: October 31, 2025

/s/ Sabrinna Soldavini

Sabrinna Soldavini
Vice President of Policy
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6462
Email: ssoldavini@mcecleanenergy.org



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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Improve the California Climate Credit.	R.25-07-013

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE ORDER INSTITUTING RULEMAKING TO IMPROVE THE CALIFORNIA CLIMATE CREDIT

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Willie Calvin,
Regulatory Case Manager

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA respectfully recommends the Commission:

- Amend the scope of this proceeding to not only adopt the IOUs' recommendations regarding clear, cost-effective, and administratively simple Climate Credit messaging, but to also develop standardized customer messaging regarding the funding source;
- Reject SDG&E's recommendation to consider Climate Credit distribution timing and eligibility, which may be interdependent, in separate phases; and
- Adopt PG&E's recommendation to amend the scope of this proceeding to develop a formal process for residential master-metered account owners to communicate changes to master-meter configurations to utilities to ensure equitable distribution of the Climate Credit.

[1] Acronyms used herein are defined in the body of this document.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Improve the California Climate Credit.	R.25-07-013

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE ORDER INSTITUTING RULEMAKING TO IMPROVE THE CALIFORNIA CLIMATE CREDIT

The California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[3] in response to the *Order Instituting Rulemaking to Improve the California Climate Credit*[4] (OIR), issued July 28, 2025.

I. INTRODUCTION

As party Opening Comments[5] demonstrate, CalCCA and other parties to this proceeding generally support the Preliminary Scope as set forth in the OIR, with some amendments. These Reply Comments respond to three points from party Opening Comments. *First*, Pacific Gas and

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[2] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[3] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021): https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf.

[4] *Order Instituting Rulemaking to Improve the California Climate Credit*, Rulemaking (R.) 25-07-013 (July 28, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M574/K655/574655670.PDF.

[5] All references herein to party Opening Comments are to the Opening Comments filed in this Rulemaking, R. 25-07-013, on or about September 26, 2025.

Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SoCalGas) (collectively, the IOUs) recommend the Commission find low-cost methods for messaging customers regarding any changes to the Climate Credit.[6] PG&E recommends that this messaging prioritize clarity, cost-effectiveness, and administrative simplicity.[7] Indeed, the first priority should be clear and understandable messaging to educate customers regarding the Climate Credit, including the funding source. To this end, the Commission should adopt standardized language for customer messaging regarding the Climate Credit. This standardized messaging aligns with the legislative intent of Assembly Bill (AB) 1207, requiring investor-owned utilities (IOU) to update Climate Credit outreach plans by January 1, 2027, and "to include a statement at the top of customer bills in applicable months specifying the amount of money saved on a utility bill in that month and attributing those savings to the climate credit and the California Cap-and-Invest Program."[8]

Second, SDG&E recommends the Commission consider changes to the timing of Climate Credit distribution separately before considering potential changes to customer eligibility.[9] SDG&E claims that timing is simpler to modify and can be expedited, while changes to eligibility are more controversial and will take more time to develop.[10] At first glance, potential changes to the timing of distributing the Climate Credit may seem straightforward, but the consideration of such changes will be intertwined with more complex questions related to equity. For example, California's diverse climate zones and varying degrees of customer access to

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6 PG&E Opening Comments, at 9; SCE Opening Comments, at 6; SDG&E Opening Comments at 6; SoCalGas, at 5.

7 PG&E Opening Comments, at 9.

8 AB 1207 (Irwin, Chapter 117, Statutes of 2025) (amending Health and Safety Code, section 748.5(a)(2)): https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202520260AB1207.

9 SDG&E Opening Comments, at 4-5.

10 *Ibid.*

technologies mean there may not be an obvious, one-size-fits-all choice for *when* the Climate Credit should be dispersed. Changes to eligibility can also affect the optimal months for Climate Credit disbursement, along with many other factors. Therefore, timing should not be discussed too hastily, nor should it be done before discussions regarding potential changes to eligibility. Instead, the Commission should consider questions of timing and eligibility simultaneously.

Third, PG&E recommends amending the scope of this proceeding with the development of a formal process for residential master-metered account owners to communicate changes in master-meter configurations.[11] PG&E's Opening Comments state that PG&E provides the Climate Credit to residential master-metered account owners, who are responsible for distributing the credit to tenants. Currently, there is no formal process for these account owners, for example, the owner of a multi-family apartment building, to communicate additions or removals of dwelling units to PG&E. This means some customers may be receiving more or less than their fair allocation of the Climate Credit or perhaps not at all. To ensure equitable distribution of the Climate Credit, the Commission should adopt PG&E's recommendation to develop a formal process for updating residential master-metered account configurations.

As set forth below, CalCCA therefore respectfully recommends the Commission:

- Amend the scope of this proceeding to not only adopt the IOUs' recommendations regarding clear, cost-effective, and administratively simple Climate Credit messaging, but to also develop standardized customer messaging regarding the funding source;
- Reject SDG&E's recommendation to consider Climate Credit distribution timing and eligibility, which may be interdependent, in separate phases; and
- Adopt PG&E's recommendation to amend the scope of this proceeding to develop a formal process for residential master-metered account owners to communicate changes to master-meter configurations to utilities to ensure equitable distribution of the Climate Credit.

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[11] PG&E Opening Comments, at 11.

II. THE IOUS' RECOMMENDATIONS FOR CLEAR, COST-EFFECTIVE, AND ADMINISTRATIVELY SIMPLE CLIMATE CREDIT MESSAGING SHOULD BE ADOPTED, ALONG WITH STANDARDIZED CUSTOMER MESSAGING REGARDING THE FUNDING SOURCE

The IOUs' recommendations for clear, cost-effective, and administratively simple Climate Credit messaging should be adopted, along with standardized messaging to ensure a clear understanding of the Climate Credit funding source. Regarding Preliminary Scoping Item (d.) and how Climate Credit allocation or distribution should be communicated to customers,[12] the IOUs recommend finding low-cost methods for messaging customers.[13] PG&E recommends that messaging be clear, cost-effective, and administratively simple and ensures "customers understand the purpose and structure of the [Climate Credit] and how the changes impact them."[14] These are reasonable priorities to pursue, and the Commission should ensure that messaging holds clarity and accuracy as the highest priority. While low-cost methods of communication will allow more funding to go directly to customers, it is important that customers easily understand this messaging and are correctly educated on what the Climate Credit is, including where Climate Credit funding originates. To facilitate this, the Commission should develop standardized customer messaging language in this proceeding as part of Preliminary Scoping Item (d.). Standardized messaging will ensure that customers are universally informed about how the Climate Credit works and how it supports bill relief for Californians. Any messaging developed as part of this proceeding should align with guidelines set previously by Decision (D.)12-12-033 and Resolution E-4611 that messaging be attributed to

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12 OIR, at 6 ("If changes are made to the Climate Credit allocation or distribution, how should these changes be communicated to customers?").

13 PG&E Opening Comments, at 9; SCE Opening Comments, at 6; SDG&E Opening Comments at 6; SoCalGas, at 5.

14 PG&E Opening Comments, at 9.

the State of California or the Cap-and-Invest program, competitively neutral, and developed in a way that does not advantage bundled customers over unbundled customers.[15]

Additionally, the California Association of Small and Multijurisdictional Utilities (CASMU) state that further educating customers on the Climate Credit is unnecessary because the program is well-established.[16] This perspective is skewed towards customers with specific backgrounds and those who may be more personally interested in energy and the environment. While many customers may know of or rely on the Climate Credit, ensuring *all* customers understand the credit and its funding source should not be overlooked. In fact, AB 1207 requires utilities to include in customer messaging a statement "at the top of customer bills in applicable months specifying the amount of money saved on a utility bill in that month and attributing those savings to the climate credit and the California Cap-and-Invest Program."[17]Developing standardized messaging on any modifications to the Climate Credit will ensure customers understand any changes and ensure the Commission and the IOUs are satisfying the legislative intent of AB 1207.

III. SDG&E'S RECOMMENDATION TO CONSIDER TIMING AND ELIGIBILITY REGARDING THE CLIMATE CREDIT IN SEPARATE PHASES SHOULD BE REJECTED

The discussion of the timing of distribution and eligibility for the Climate Credit should occur simultaneously because the two topics affect each other. SDG&E recommends bifurcating the consideration of how and when the Climate Credit is distributed into two separate phases and

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[15] D.12-12-033, *Decision Adopting Cap-and-Trade Greenhouse Gas Allowance Revenue Allocation Methodology for the Investor-Owned Electric Utilities*, R.11-03-012 (Dec. 20, 2012), at 198, Conclusion of Law 47; *see also* Resolution E-4611 (Oct. 17, 2013), at 26, Finding 27 (requiring IOU plans regarding GHG allowance revenue return education and outreach to be competitively neutral).

[16] CASMU Opening Comments, at 5.

[17] AB 1207 (amending Health and Safety Code, section 748.5(a)(2)).

claims that the question of timing distribution is simpler than determining eligibility.[18] This is an oversimplification of how the timing of the Climate Credit impacts customers differently. Optimal timing to support bill affordability with the Climate Credit for residential customers may depend on where a customer lives and what technology they have access to. For example, a customer who lives inland in Southern California and has an old air conditioner may have a different "highest bill" month than a customer in coastal Northern California who uses electricity for heating. The question of timing is intertwined with eligibility in that both have impacts on how much bill relief any given customer will receive. Potential changes to eligibility may also affect which months are considered the most high-billed months for those customers due to where the majority of those customers reside. Therefore, the Commission should reject SDG&E's recommendation to discuss timing and eligibility in separate tracks of this proceeding.

IV. PG&E'S PROPOSAL TO DEVELOP A FORMAL PROCESS REGARDING MASTER METERS TO ENSURE CUSTOMER EQUITY SHOULD BE ADOPTED

PG&E's proposal that the Commission develop a formal process regarding master meters to ensure customer equity should be adopted. PG&E recommends adding to the scope of this proceeding a review of the treatment of legacy gas and electric master-metered residential households.[19] PG&E explains that Climate Credits get distributed to master-metered residential account owners, such as the owners of multifamily apartment buildings and mobile home parks, who are responsible for passing the credit to tenants.[20] The legacy nature of this system means PG&E, and potentially other IOUs, lack a formal process for master-metered residential account owners to update records when master-meter configurations change, such as adding or removing dwelling units. This affects how many tenants receive Climate Credits, leading to some customers

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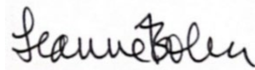
[18] SDG&E Opening Comments, at 4-5.
[19] PG&E Opening Comments, at 11.
[20] *Ibid.*

potentially receiving larger or smaller credits than equitable, or some customers not receiving credits at all. The Commission should adopt PG&E's recommendation to amend the scope to include establishing a formal process for residential master-metered account owners to notify IOUs of changes to their master-meter configuration to ensure customers receive their equitable share of the Climate Credit.

V. CONCLUSION

CalCCA appreciates the opportunity to submit these reply comments and respectfully requests adoption of the recommendations proposed herein.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

October 13, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 25-05-011 (Filed May 15, 2025)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

PUBLIC VERSION

Leanne Bober
Director of Regulatory Affairs and Deputy General Counsel
Willie Calvin
Regulatory Case Manager

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9815
E-mail: regulatory@cal-cca.org

Nikhil Vijaykar
Tim Lindl
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (408) 621-3256
E-mail: nvijaykar@keyesfox.com
tlindl@keyesfox.com

October 24, 2025

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SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS[1]

Contested Issues

- The Commission should adopt CalCCA's proposal to credit the value of all banked RECs (including pre-2019 banked RECs) to the PCIA vintage corresponding to the year in which those banked RECs were originally generated. Doing so will ensure that all customers receive the benefit of the RECs for which they paid.

- The Commission should reject the SoD RA valuation proposal PG&E advances in its direct testimony. That proposal practically eliminates all battery storage capacity value, produces nonsensical results in the PCIA and fails to comport with basic market realities.

- The Commission should also reject the SoD RA valuation proposal PG&E advances in its rebuttal testimony:

  - PG&E raised its revised proposal at the last minute in this proceeding and responded to discovery regarding that proposal only two business days before the commencement of an evidentiary hearing in this proceeding. Parties have therefore not had the opportunity to rigorously evaluate that methodology or analyze the results it produces.

  - PG&E's revised RA valuation methodology would produce different results if applied to a different LSE, depending on how each LSE dispatches its batteries—an outcome that is illogical in the context of the PCIA, where the purpose is to determine the value of the battery if it were bought or sold in the market by any LSE.

  - PG&E advances its revised proposal in an effort to compromise with CalCCA and not as a reasonable approach to calculating the RA value of its PCIA portfolio.

  - PG&E's revised methodology appears to assign storage resources significantly less capacity value than the value PG&E itself assigns storage resources when evaluating procurement opportunities for its bundled customers, indicating the methodology is not sound.

- The Commission should evaluate the question of how best to reflect the impact of SoD on the value of RA for PCIA ratemaking purposes in Track 2 of the PCIA Rulemaking. The final answer to the question of what impacts SoD will have on the PCIA framework may be a combination of modifications to RA quantity and price, but the Commission, the three IOUs, and interested parties like CalCCA should conduct further analysis in the PCIA OIR before reaching a conclusion on how best to value capacity under the SoD framework.

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[1] Acronyms and defined terms used in this Summary of Recommendations are defined in the body of this Brief.

Until that analysis occurs, the Commission should not disturb PG&E's existing approach to valuing its RA capacity.

- If the Commission adopts an interim change to PG&E's existing approach to valuing the RA capacity of its PCIA portfolio, it should adopt SCE's Interim SoD Method and reject both of PG&E's proposal(s).

- The Commission should expeditiously grant CalCCA's AFR of D.25-06-049 and should not require PG&E to true-up its 2025 RA MPB using a Final 2025 RA MPB derived from the newly revised calculation methodology adopted in that decision.

    - If the AFR is granted soon after this brief is filed, an Assigned Commissioner Ruling should be issued in this proceeding to require (1) Energy Division to recalculate the Final RA MPB using the correct formula; and (2) PG&E to recalculate the Portfolio Market Value, and the resulting PCIA rates, in a supplement to its October Update.

    - If the AFR is granted well after PG&E's October Update, but prior to a final decision in this proceeding, the final decision should require (1) Energy Division to recalculate the Final RA MPB using the correct formula; and (2) PG&E to recalculate the Portfolio Market Value, and the resulting PCIA rates, in its year-end consolidated rate change using the correct formula.

    - If the AFR is not granted prior to a final decision in this proceeding, the final decision should include an ordering paragraph that enables either a subsequent phase, or next year's iteration, of this proceeding to address the necessary changes to PCIA rates on account of the resolution of the AFR.

Uncontested Issues

- PG&E correctly assumes that new data center load located in CCA service territory will default to CCA service unless the customer opts out.

- If the Commission adopts PG&E's SoD proposal, it should require PG&E to correct the Retained RA from ModCAM storage resources.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U 39 E)	Application No. 25-05-011 (Filed May 15, 2025)

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

Pursuant to Rule 13.12 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission) and the schedule adopted in the Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo)[2] as modified by the Administrative Law Judge's Email Ruling Small Business Utility Advocates Procedural Request for Extension of Briefing Schedule (Pacific Gas & Electric) 2026 Energy Resource Recovery Account) issued October 17, 2025, the California Community Choice Association[3] (CalCCA) hereby submits this Opening Brief regarding the *Application of Pacific Gas and Electric Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery*

[2] Assigned Commissioner's Scoping Memo and Ruling at 4 (Jul. 31, 2025).

[3] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E) (Application).[4]

I. INTRODUCTION

A central purpose of the investor-owned utilities' (IOU) annual ERRA Forecast proceedings is to set Power Charge Indifference Adjustment (PCIA) rates for the upcoming year. The PCIA is the mechanism the Commission uses to ensure "indifference" between bundled and departed customers, as required by California law. To achieve that objective, PCIA rates are set at levels that ensure departed customers remain responsible for the costs of PCIA resources previously incurred on their behalf—but only those costs that remain after the Commission accounts for the benefits PCIA resources continue to impart to bundled customers.

For more than a decade, the PCIA framework has sought to ensure both bundled and unbundled customers benefit from the PCIA-eligible resources in PG&E's portfolio for which they both pay. For bundled customers, PG&E uses the attributes from those resources to meet compliance obligations. For departed customers, PG&E credits the value of those attributes against the costs departed customers owe to bundled customers. In this way, PCIA rates strike a fine balance.

That balance is upset when an IOU proposes to use attributes from its PCIA portfolio to benefit bundled customers without conveying a proportionate share of those benefits to the departed customers who pay for those resources. Such one-sided utility proposals inflate the PCIA

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[4] *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2026 Energy Resource Recovery Account (ERRA) and Generation non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E),* Application (A.) 25-05-011 (May 15, 2025).

and result in impermissible cost shifts from bundled to departed customers. California law requires the Commission to avoid those cost shifts.

In this proceeding, PG&E makes two proposals that would allow bundled customers to continue to benefit from the attributes of PG&E's PCIA resources while depriving unbundled customers of their fair and proportionate share of those benefits: (1) a proposal related to the Renewables Portfolio Standard (RPS) value of PG&E's PCIA portfolio; and (2) a proposal related to the Resource Adequacy (RA) value of the same portfolio. Each proposal would result in massive impacts to the PCIA revenue requirement. The RPS-related proposal would increase that revenue requirement by [redacted], and the RA-related proposal would either increase the PCIA revenue requirement by [redacted] (original proposal) or by [redacted] (revised proposal). These impacts would exacerbate already-massive PCIA rate increases PG&E forecasts in its October Update, compromising customer affordability for unbundled customers. The Commission should not adopt either of these proposals.

First, consistent with its practice in past years, PG&E proposes to use surplus Renewable Energy Credits (REC) it banked in years prior to 2019 to cover a shortfall in the RECs it needs to meet its bundled customer "Minimum Retained RPS" requirement in 2026. However, in a sharp departure from its prior practice, PG&E does not propose to give <u>all</u> customers that originally paid for those RECs the benefit of those RECs. Instead, PG&E proposes to allow its current bundled customers to use pre-2019 banked RECs for compliance while denying departed load customers their fair share of the value of those RECs.

PG&E's proposal violates Section 366.2(g) of the Public Utilities Code.[5] That statute requires PG&E provide departed customers the value of any benefits associated with PG&E's PCIA resources that remain with bundled service customers. PG&E's proposal violates Section 366.2(g) because, as PG&E's witness admitted during hearing, the departed customers who previously paid for a portion of the banked RECs PG&E now seeks to use neither benefit from the retirement of the banked RECs nor ever receive a credit for PG&E's use of those banked RECs towards bundled customer compliance. This outcome plainly violates Section 366.2(g).

Moreover, PG&E's proposal violates the settled indifference framework the Commission has established over the past two decades via its decisions applying the law, including decisions addressing the RPS value of the IOUs' portfolios beginning with Decision (D.) 11-12-018. The indifference framework requires PG&E to value RECs used by bundled customers at the RPS market price benchmark (MPB) when calculating PCIA rates. Decision 19-10-001 introduced several changes to the PCIA framework, but left intact an important piece of the settled indifference framework: if RECs are retired on bundled customers' behalf, departed customers must receive value for those benefits retained by bundled customers, via a credit to the PCIA at the RPS Adder. The Commission should therefore adopt CalCCA's pre-2019 banked REC proposal, which directs PG&E to apply a credit to the PCIA vintage corresponding to the year the banked REC was generated and paid for. It is the only outcome that complies with the law.

Second, PG&E makes multiple proposals to change the way it calculates the capacity value of battery storage resources in its PCIA portfolio to account for the implementation of the Slice-of-Day (SoD) methodology within the Commission's RA compliance program. First, in direct

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[5] All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

testimony describing PG&E's original RA SoD proposal, PG&E proposes to average the hourly discharge of its PCIA-eligible battery resources (a positive number) and the charging of the batteries (a negative number), resulting in offsetting positive and negative RA capacity values associated with those resources. The upshot of this methodology is that it assigns PG&E's PCIA-eligible battery resources a <u>near-zero capacity value</u>. This essentially takes the RA attributes from those resources—attributes for which its departed customers pay—and allows PG&E to use that RA attribute for bundled customer compliance for free. That result is not only a striking departure from PG&E's current approach to RA valuation and fundamentally unfair, but it fails to comport with market realities. Battery storage capacity is not free. If PG&E had to go to the market to purchase battery storage RA, it would pay a seller for that RA. No seller would allow PG&E to offset the purchase price for that RA by the cost to PG&E of charging the battery. And neither PG&E nor any seller would accept a zero-dollar bid for a battery's capacity attribute if they were to sell that capacity into the market.

The same logic applies when PG&E uses a battery from its PCIA portfolio to meet its bundled customers' compliance obligations. Departed customers pay for those resources and must receive a corresponding credit for the RA capacity attributes of those resources when used for bundled customer compliance. That credit to departed customers is essentially a payment for the use of those attributes. Again, those attributes are not free; on the contrary, load-serving entities (LSEs) are paying high prices in a tight RA market. Thus, PG&E's original RA SoD proposal fails to convey to departed customers their fair and proportionate share of the RA capacity benefits from storage resources in violation of Section 366.2(g). The Commission should reject PG&E's original RA SoD proposal.

The Commission should also reject PG&E's revised RA SoD proposal. Advanced in the eleventh hour in this proceeding, the timing of PG&E's revised RA SoD proposal leaves parties no meaningful opportunity to evaluate that proposal or analyze the results it produces. PG&E included its revised proposal in its rebuttal testimony filed on the afternoon of September 23, 2025. Certain workpapers supporting that revised proposal were then provided on the afternoon of September 24 (although PG&E refused to prepare and produce workpapers showing the impact of its revised proposal on the PCIA[6]). CalCCA served PG&E lengthy discovery on the revised proposal on September 26, and PG&E responded to that discovery on October 3, two business days before the commencement of the evidentiary hearing. This highly compressed process underlines exactly why the Commission does not typically permit policymaking in expedited ERRA Forecast proceedings. The expedited timeline, limited stakeholder participation, and narrow scope of ERRA Forecast proceedings simply do not permit the Commission to thoroughly evaluate new policy proposals in these proceedings. Instead, ERRA Forecast proceedings focus on implementing existing Commission decisions, rules, regulations and guidance. The Commission defers thornier policy issues impacting all three IOU service territories to rulemakings and other dockets where all three IOUs are parties and a broad set of stakeholders have an opportunity to develop a record.

Putting aside CalCCA's procedural concerns with PG&E's revised RA SoD proposal, the revised proposal is also substantively defective for two reasons. First, as PG&E acknowledged in response to CalCCA's discovery and during cross examination, the outputs of the revised proposal—like the original proposal—depend on the manner in which PG&E dispatches its batteries. That means the methodology, if applied to other LSEs, would produce different results

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[6] *See* Exh. CalCCA-12.

for each LSE. This result makes no sense in the context of the PCIA, where the objective is to determine the value of the battery if it were bought or sold to any LSE—not just PG&E. Battery storage RA value should not be driven by one LSE's dispatch optimization decisions. Put differently, a seller in the market would not discount the price of the battery resource being sold to reflect the way a particular buyer plans on using the battery.

Second, PG&E's revised proposal produces a storage RA value that is significantly lower than the value PG&E assigns storage resources when it evaluates procurement opportunities for bundled customers. This indicates PG&E's revised methodology is not reasonable, even though the results of the revised methodology are better-aligned with market realities than PG&E's original proposal, which would assign batteries a near-zero capacity value.

Given the deficiencies of both PG&E's original and revised RA SoD proposals, the Commission should reject both proposals. Further, the Commission should holistically consider the impact of SoD on the PCIA in Track Two of the PCIA Rulemaking, and direct PG&E to retain its current RA valuation methodology until this issue is comprehensively resolved in that Rulemaking. If the Commission instead moves forward with adopting an interim change to PG&E's existing approach to valuing the RA capacity of its PCIA portfolio, it should adopt Southern California Edison's (SCE) Interim SoD Method discussed in CalCCA's testimony.

Beyond these REC and SoD RA issues, PG&E's October Update uses the Commission-issued Final 2025 RA MPB, derived from a newly revised calculation methodology adopted in D.25-06-049, to reset the revenue requirement underlying the 2025 rates customers currently pay. CalCCA filed an Application for Rehearing (AFR) of D.25-06-049 because requiring PG&E to value its 2025 PCIA capacity portfolio using an MPB derived from a newly revised calculation methodology constitutes unlawful retroactive ratemaking. The Commission should grant

CalCCA's AFR and, depending on the timing of that decision, take the steps outlined in this brief to avoid perpetuating retroactive ratemaking.

Finally, this brief summarizes and addresses two uncontested issues discussed in the testimony of CalCCA witness Dickman: (1) PG&E's assumption that new data center load will be served by community choice aggregators (CCAs); and (2) PG&E's calculation of Retained RA associated with Modified Cost Allocation Mechanism (ModCAM) resources.

II. LEGAL STANDARDS

Considering the significant impact PG&E's Application will have on both departed and bundled customers, the ratemaking proposals in the Application require the Commission's careful consideration under the applicable legal standards. Those legal standards include requirements established by the Public Utilities Code. They also include those requirements established in prior Commission decisions, rules, regulations and resolutions creating and subsequently modifying the regulatory framework for the utilities' annual ERRA Forecast filings.

First, pursuant to Public Utilities Code Section 451:

> All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.[7]

This foundational "just and reasonable" statutory requirement is applicable to all rates and charges, including those that will be established by this ERRA Forecast proceeding. Commission precedent supports cost-causation principles in setting "just and reasonable" rates, whereby customers are

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[7] Pub. Util. Code § 451.

responsible for the costs incurred on their behalf.[8] The Public Utilities Code also requires rates to be non-discriminatory. Public utilities are prohibited from establishing "any unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service."[9]

ERRA Forecast proceedings also implicate statutory prohibitions on cost shifts between groups of bundled and unbundled customers, as PG&E emphasizes in its Application.[10] Section 365.2 of the California Public Utilities Code mandates indifference for departed customers, requiring the Commission to "ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."[11] Under Section 366.2, unbundled customers are responsible solely for "estimated net unavoidable electricity costs" when determining indifference, and those costs must be reduced by the benefits in the IOUs' portfolios that accrue to bundled customers.[12]

Further, in the Commission's unique ERRA Forecast applications, where policymaking is largely forbidden,[13] the utility rarely requests the recovery of costs that have not already been approved via a prior decision. Additionally, the allocation of costs among different customer

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[8] D.15-07-001 at 2 (Jul. 13, 2015) (citing *K N Energy, Inc. v. F.E.R.C.*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."); *Alabama Elec. Co-op., Inc. v. F.E.R.C.*, 684 F.2d 20, 27 (D.C. Cir. 1982) ('[I]t has come to be well established that electrical rates should be based on the costs of providing service to the utility's customers, plus a just and fair return on equity."); *So. Cal. Edison Authorized to Increase Rates for California Intrastate Electric Services*, 75 CPUC 641 (1973) (recognizing the desirability of each group's bearing its fair share of the cost of service, as such share is measured by the cost of service study); D.10-09-010 (Sept. 2, 2010). The decision further notes, "For this reason a cost of service study is part of each general rate case for establishing electricity rates." D.15-07-001 at 2-3 n.3.

[9] Pub. Util. Code § 453(c).

[10] Application at 8-9.

[11] Pub. Util. Code § 365.2.

[12] Pub. Util. Code §§ 366.2 (f)(2), (g).

[13] D.18-01-009 at 10 (finding that policy issues and other industry-wide practices such as changes to the PCIA methodology are properly addressed in rulemaking dockets, such as R.17-06-026).

groups and classes is pre-determined via the utility's GRC. Instead, the Commission implements prior decisions, resolving any ambiguity in those decisions necessary to enact rates for the forecast year.

Here, however, PG&E has requested two significant changes to the policies underlying its ratemaking, neither of which are required by prior Commission decisions: (1) the manner in which PG&E accounts for banked RECs used to satisfy its Minimum Retained RPS obligation; and (2) the methodology PG&E applies to calculate the RA value of its PCIA-eligible portfolio. Thus, not only must PG&E's proposed PCIA revenue requirement and rates comply with all applicable rules, regulations, resolutions, and decisions for all customer classes, the Commission must now also consider whether PG&E's new banked REC and RA valuation proposals are reasonable, and whether those proposals illegally shift costs to other customers.[14] For the reasons explained in this brief, PG&E's banked REC and RA valuation proposals are unjust and unreasonable and would result in impermissible and unlawful cost shifts if approved.

Finally, in its testimony, PG&E states it "intends to use the 2025 Final RA MPB to be issued by Energy Division in October 2025 for the purpose of PG&E's Fall Update."[15] The Commission should not require PG&E to true-up its Forecast 2025 RA MPB using the Final 2025 RA MPB released by Energy Division in October 2025, because doing so will perpetuate unlawful retroactive ratemaking. CalCCA discusses the relevant law prohibiting retroactive ratemaking in Section V.A. of this Brief.

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[14] *See, e.g.*, Scoping Memo at 3.
[15] PG&E-04 at 1-3.

III. BURDEN OF PROOF

As the ratemaking applicant, PG&E has the burden of proof on all aspects of its Application and must therefore affirmatively establish the lawfulness and reasonableness of each proposal therein.[16] That burden of proof includes a burden of production, which rests with PG&E on all facts material to its Application. The burden of production requires PG&E to present evidence sufficient to establish disputed facts in its favor by a requisite degree of belief—which in ERRA Forecast proceedings is a "preponderance of the evidence."[17] The burden of proof also includes a burden of persuasion, which remains with PG&E throughout this proceeding.[18] That means the Commission should not grant the relief PG&E requests unless a preponderance of the record evidence demonstrates PG&E has affirmatively satisfied its burden of proof with respect to that request.

IV. STANDARD OF REVIEW

The Commission has previously determined that Section 1757 of the Public Utilities Code applies to ratesetting proceedings[19] such as the instant Application,[20] which means the final decision must be "supported by the findings," and those findings must be "supported by substantial evidence in light of the whole record" to withstand appeal. Therefore, the Commission should not grant the relief in PG&E's Application without substantial evidence to support the rates

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[16] D.23-08-027 at 15.

[17] *See, e.g.*, D.18-01-009 at 9-10; D.15-07-044 at 29 (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting proceeding, but noting that the preponderance of evidence is the "default standard to be used unless a more stringent burden is specified by statute or the Courts.")

[18] *Cal. Farm Bureau Fed. V. State Water Resources Control Bd.*, 51 Cal. 4th 421, 436 (2011).

[19] Pub. Util. Code § 1757; *see, e.g.* D.20-05-027 at 5-6 (stating "As an initial matter, SDG&E cites to the wrong statute, because Public Utilities Code section 1757.1 does not set forth the applicable standards for a ratesetting proceeding like this one. Rather, section 1757 provides the appropriate standard and requires a finding as to whether the Commission's findings are not supported by substantial evidence in light of the whole record.").

[20] Scoping Memo at 5.

requested.[21] California courts will overturn Commission decisions that are not supported by substantial evidence.[22] Mere rubber-stamping of uncorroborated, disputed evidence does not meet this standard.[23] The Commission, therefore, must reject the components of PG&E's Application that are not supported by substantial evidence.

V. BACKGROUND

This brief focuses on three contested proposals in PG&E's Application: (1) the proposal to true-up PG&E's Forecast 2025 RA MPB using the Final 2025 RA MPB released by Energy Division in October 2025 (Scoping Issue 1); (2) PG&E's proposal to no longer credit departed customers for its use of pre-2019 banked RECs towards bundled customer compliance obligations (Scoping Issue 2); and (3) PG&E's proposal to substantially modify its methodology for calculating the Retained RA value of its PCIA portfolio (Scoping Issue 3). Each of those proposals directly impact CCAs' interests because those proposals, if adopted, would have the effect of increasing the PCIA revenue requirement, and, all else equal, increasing the PCIA rates customers pay. Below, this brief provides background on the PCIA, the calculation of the PCIA revenue requirement, and the allocation of the PCIA revenue requirement to customer vintages. This background provides the context necessary to understand the impact of PG&E's proposals on customers.

A. BACKGROUND ON THE PCIA

CCA customers receive generation services from their local CCA, and receive transmission, distribution, billing, and other services from the incumbent for-profit utility. CCA

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[21] Pub. Util. Code § 1757(a)(4). *See, e.g. The Utility Reform Network v. Pub. Util. Comm'n*, 223 Cal. App. 4th 945, 958-59 (Feb. 5, 2014).
[22] *Id*.
[23] *Id*.

customers pay CCA-specific generation rates. CCA rates vary and are partially influenced by local mandates to procure and maintain clean electricity portfolios that, in many cases, exceed state requirements for renewable generation. In addition, CCA and other unbundled customers are subject to several non-bypassable charges (NBC), including the PCIA and the Cost Allocation Method (CAM) surcharge, the 2026 levels of which will be determined in this proceeding.

As explained above, the Commission has an obligation to ensure "indifference," meaning when customers of IOUs depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[24] The PCIA is the tool the Commission adopted "intend[ing] to equalize cost sharing" between these two groups of customers.[25]

B. CALCULATION OF THE PCIA REVENUE REQUIREMENT

The PCIA revenue requirement is derived from two sources in each utility's ERRA forecast case, as demonstrated in Figure 1. The first is the Indifference Amount forecasted for the year *for which* rates are being set, *i.e.*, the Indifference Amount forecasted for 2026 in the instant proceeding.[26] The second is the final PCIA revenue requirement for the year *in which* rates are being set, *i.e.*, the final 2025 PCIA revenue requirement in the instant proceeding, which is derived from the balance in the Portfolio Allocation Balancing Account (PABA) the utility anticipates seeing at the end of the year.[27]

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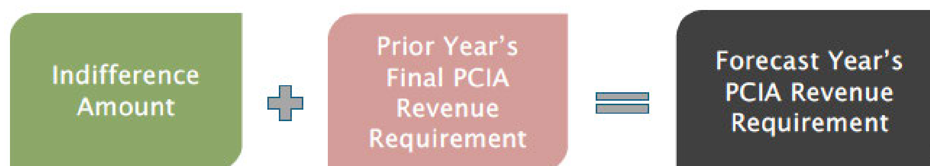
[24] *Scoping Memo and Ruling of Assigned Commissioner*, R.17-06-026 (Sept. 25, 2017), at 2; *see also* D.18-10-029 at 3.

[25] *See* D.18-10-019 at 3.

[26] Exh. CalCCA-01C at 5.

[27] *Id*.

FIGURE 1[28]



The Indifference Amount is the difference between the forecasted cost of the IOU's supply portfolio and the forecasted market value of the IOU's supply portfolio as demonstrated in Figure 2 below.[29]

FIGURE 2[30]

Total Utility Portfolio Cost includes:

(i) the cost for Utility-Owned Generation (UOG) (*i.e.*, the capital investment recovery and fixed maintenance costs the Commission sets in a GRC,

(ii) purchased power such as that from power purchase agreements (PPAs),

(iii) fuel costs for UOG and PPAs with tolling agreements, and

(iv) California Independent System Operator (CAISO) grid charges and revenues, net of any sales.[31]

The forecasted Portfolio Market Value is derived from total eligible resource output multiplied by the MPBs, an administratively determined set of proxy values that is intended to

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28 *Id.*

29 *Id.*

30 *Id.*

31 D.11-12-018 at 8-9.

estimate the market value of the IOU's resource portfolio.[32] Portfolio Market Value consists of three principal components: Energy Value, RPS Value, and RA Value.

- Energy Value is the estimated financial value, measured in dollars, that is attributed to the generation component of a utility portfolio for a given year.[33]
- RPS Value is the estimated financial value, measured in dollars, that is attributed to the renewable energy component of a utility portfolio for a given year above and beyond the Energy Value.[34]
- RA Value is the estimated financial value, measured in dollars, that is attributed to the resource adequacy component of a utility portfolio for a given year.[35]

MPBs are estimates of the value per unit (not total portfolio value) associated with the three principal sources of value in utility portfolios (non-RPS energy, RPS, and RA capacity).[36] Each MPB must be multiplied by the relevant portfolio volume as part of the overall calculation of Portfolio Market Value:[37]

- Energy Index is the MPB that reflects the estimated market value of each unit of energy in a utility portfolio, in dollar value per megawatt hour ($/MWh). It is sometimes referred to as "Brown Power Index," "Brown Power component," "Brown Power Adder," or "Brown Power benchmark."[38]

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[32] D.19-10-001 at 6 ("Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the Power Charge Indifference Adjustment for a given year.")

[33] *Id.*

[34] *Id.*

[35] *Id.*

[36] *Id.*

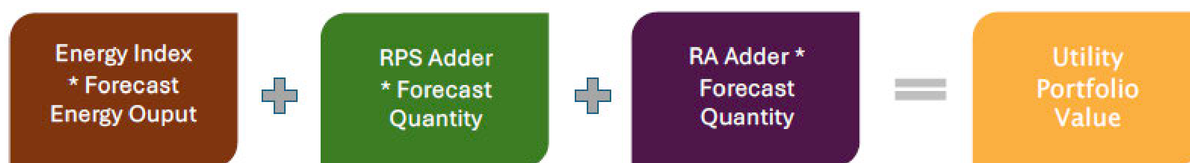
[37] *Id.*

[38] *Id*. at 7.

- RPS Adder is the MPB that reflects the estimated value (incremental to the Energy Index) of each unit of RPS-eligible energy that is attributable to its RPS eligibility, in $/MWh.[39]
- RA Adder is the MPB that reflects the estimated value of each unit of capacity in a utility portfolio that can be used to satisfy Resource Adequacy obligations, in dollar value per kilowatt ($/kW-month).

The forecast utility portfolio value calculation is shown in Figure 3 below.

FIGURE 3[40]



The forward-looking, forecasted ingredients of total portfolio cost and value are netted to produce the Indifference Amount portion of the PCIA revenue requirement.[41]

The second portion of the PCIA revenue requirement is the "true up." The "true up" modifies the forecasted PCIA revenue requirement from the prior year to reflect, among other things, actual revenues received for products sold from the portfolio and to reflect a zero-dollar value for products left unsold from the portfolio.[42] The revenue requirement modification also updates the proxy market values for products the utilities used to serve bundled customers,

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39 *Id.*
40 Exh. CalCCA-01C at 7.
41 *Id.* at 7.
42 *Id.* at 8.

changing the *forecast* energy, RPS, and RA MPBs to *final* energy, RPS, and RA MPBs.[43] This "true-up" relies on the same methodology used for the forecast and determines the final portfolio value, as shown in Figure 4 below:[44]

FIGURE 4[45]

Prior to D.18-10-019, the PCIA rate was set only on a forecast basis with no after-the-fact adjustment to the forecasted PCIA revenue requirement for unbundled customers.[46] Decision 18-10-019 approved such an adjustment via the PABA, a rolling balancing account tracking the difference between costs and revenues used to determine the forecasted PCIA revenue requirement and the actual costs and revenues PG&E realizes during the year related to its PCIA-eligible resource portfolio.[47]

PG&E calculates this final 2025 portfolio value, uses it as an input to the actual 2025 indifference amount, and finalizes the 2025 revenue requirement in this case, as shown below in Figure 5.[48]

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43 *Id*. at 8.

44 Because the true-up for 2025 occurs during 2025, this true-up is developed using (1) actual values that are available to date and (2) a forecast of actual values for the remainder of the year. PG&E's Application includes an estimate of the 2025 year-end PABA balance comprising a combination of actual entries from January through March 2025 and a projection of activity from April through December 2025. PG&E's October Update should include an estimate of the 2025 year-end PABA balance comprising a combination of actual entries from January through August 2025 and a projection of activity from September through December 2025. The final December 31, 2025, advice letter implementing the proceeding will include actual entries. id. at 8, fn. 15.

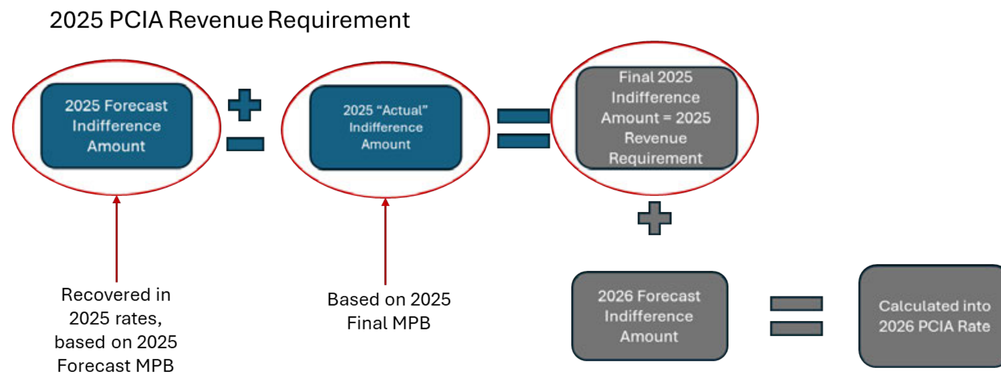
45 *Id*. at 8.

46 *Id*.

47 *Id*.

48 *Id*. at 9.

FIGURE 5[49]



To summarize, PG&E's PCIA rates for 2026 will be set in this proceeding based on these two components: (1) the forecasted Indifference Amount, *i.e.*, the difference between the forecasted cost of PG&E's generation portfolio in 2026 and the forecasted market value of PG&E's generation portfolio in 2026; and (2) the final 2025 PCIA revenue requirement based on the year-end balance in the PABA.[50] The Indifference Amount and the final 2025 PCIA revenue requirement are added together to form the 2026 PCIA revenue requirement recovered through rates from bundled and unbundled customers.[51]

C. CUSTOMER VINTAGING AND ALLOCATION

Each generation resource and customer is assigned a "vintage."[52] A distinct portfolio of generation resources is identified for each vintage year based on when a commitment to procure each resource was made.[53] Customers are assigned to vintage years according to the date the customer departed bundled IOU service.[54] Customers continuing to receive bundled service from

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[49] *Id.*
[50] *Id.*
[51] *Id.*
[52] *Id.*
[53] *Id.*
[54] Unlike portfolio resources, customers are assigned to vintages using a July to June calendar period. For example, customers departing bundled service between July 2019 and June 2020 are assigned to the 2019 vintage. *See id.* at 10, fn. 16.

the IOU are included in the latest vintage (e.g., vintage 2026 in the current application).[55] Each vintage is assigned both a separate Indifference Amount and a separate final 2025 revenue requirement.[56] Customers are responsible for the cumulative Indifference Amount for years prior to and including their vintage.[57] The PCIA revenue requirement is allocated among both bundled and unbundled customers based on their vintage and their rate class using the allocation factors from PG&E's most recently approved GRC.[58]

VI. CONTESTED ISSUES

A. PG&E'S BANKED REC PROPOSAL UNLAWFULLY DENIES DEPARTED LOAD THEIR FAIR SHARE OF THE VALUE OF RECS USED TO BENEFIT BUNDLED CUSTOMERS (SCOPING ISSUE 2)

Scoping Issue 2 asks: "Did D.19-01-001 establish a methodology for treatment of pre-2019 banked RECs? If not, how should PG&E value pre-2019 banked RECs for the purpose of calculating the PCIA?" Section 366.2(g) of the Public Utilities Code, and a long line of Commission decisions implementing the indifference principle established by state law require PG&E to value all RECs used for bundled customer compliance—including "pre-2019" banked RECs—at the RPS Adder applicable in the year those RECs are used.[59]

Section 366.2(g) of the Public Utilities Code requires that departed load customers receive the value of any benefits associated with PG&E's PCIA resources where those benefits remain with bundled service customers.[60] As described above, this requirement is effectuated in the PCIA framework by applying the appropriate MPB to the sources of value in the IOU's PCIA portfolio.

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[55] *Id*. at 10.
[56] D.11-12-018 at 9.
[57] Exh. CalCCA-01C at 10.
[58] D.18-10-019 at 122 and Ordering Paragraph (OP) 4; Exh. CalCCA-01C at 10.
[59] D.19-10-001.
[60] Pub. Util. Code § 366.2(g).

Accordingly, per the PCIA framework, departed load receives the value of PG&E's RPS-eligible resources retained for bundled customer RPS compliance by applying the RPS Adder to the volume of "Retained RPS" generation.

What the Commission now labels as "Retained RPS" has been treated the same since the Commission created a new MPB to reflect the RPS value of certain RPS-eligible resources fifteen years ago, in D.11-12-018.[61] Per that decision, RECs retained for the benefit of bundled customers are valued at the applicable RPS Adder.[62] To the extent the REC was previously purchased by bundled customers at the time it was generated, the value of that REC should be credited to the PCIA vintage corresponding to the year it was generated to ensure both bundled and unbundled customers are treated fairly. PG&E's banked REC proposal in this proceeding fails to comport with Section 366.2(g), Commission precedent implementing the indifference framework established in California law (including D.19-10-001 and its predecessors), and basic logic. PG&E proposes to apply pre-2019 banked RECs towards bundled customer compliance while denying departed load their fair share of the value of those RECs.

Stated simply, PG&E's current bundled customers in 2026 should be responsible for the cost of RPS compliance on their behalf in 2026. And unbundled customers should receive credit for the value of RPS attributes they previously paid for but that are now being used for bundled customer RPS compliance. If previously banked RECs are used for current bundled customer compliance, there must be a credit in PG&E's Indifference Amount that conveys the appropriate portion of the value of those RECs to departed load, ensuring that the cost of bundled customer compliance is not shifted to departed load customers and that the value of resources departed load

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[61] *See* D.11-12-018 at OP 2 to OP 5.
[62] *Id*. at OP 2.

customers paid for originally is received by those customers. The Commission should reject PG&E's Banked REC proposal as it pertains to pre-2019 banked RECs.

1. Issue Introduction and Executive Summary.

When PG&E uses RPS-eligible generation from its PCIA resource portfolio to meet its bundled customer RPS compliance target, it must count that RPS-eligible generation as Retained RPS and credit the value of that generation to the PCIA using the RPS Adder.[63] More specifically: bundled customers pay for the RECs needed for RPS compliance via their generation rates—Retained RPS is debited to ERRA and credited out of the PCIA.[64] This accounting practice reflects the fundamental indifference principle that underpins the PCIA framework. Where bundled customers retain the value of any benefits associated with PG&E's PCIA portfolio, the law requires PG&E credit unbundled customers with their proportionate share of those benefits.[65]

Per the Commission's directive in D.20-02-047,[66] PG&E must retain a minimum volume of RPS-eligible generation corresponding to PG&E's RPS compliance period requirement.[67] This is known as PG&E's "Minimum Retained RPS" requirement. If RPS-eligible generation available to PG&E in the Forecast year (in this case, 2026) is less than its annual RPS compliance requirement for bundled customers, PG&E may use "banked" RECs to make up the difference and meet the minimum Retained RPS requirement established by the Commission.[68] "Banked" RECs are RECs PG&E generated in previous years in excess of PG&E's RPS compliance period requirement.[69]

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63 Exh. CalCCA-01C at 35.
64 *Id*.
65 Pub. Util. Code § 366.2(g).
66 D.20-02-047 at 13-14.
67 Exh. PGE-01E at 8-15.
68 *See id*. at 8-18 to 8-19; Exh. CalCCA-01C at 36.
69 Exh. CalCCA-01C at 36.

Banked RECs were paid for (as Retained RPS) by the customers who were bundled at the time the RECs were generated.[70] When banked RECs are ultimately used towards bundled customer RPS compliance, years after they were initially generated, PG&E's bundled customers extract the value they previously paid for.[71] However, PG&E's bundled customer pool evolves (and has generally dwindled) over time, as more customers depart for CCA service.[72] Therefore, a specific subset of PG&E's customers who were bundled at the time a banked REC was generated, but departed before PG&E could use that REC towards compliance, exists.[73] Those "Now-Departed" customers do not benefit from PG&E's use of banked RECs towards bundled customer compliance.[74] The PCIA framework, and over a decade of Commission decisions establishing that framework, therefore demand that "Now-Departed" customers receive value for the banked RECs they previously paid for, through a credit to the PCIA at the RPS Adder.

An example helps clarify the moving pieces involved in this issue using an illustrative year prior to 2019. For instance, PG&E generated RECs in surplus of its RPS compliance obligations in 2015. Decision 11-12-018 required PG&E to value those RECs at the RPS Adder when those RECs were generated. As a result, the customers taking bundled service from PG&E in 2015 paid for those RECs (including the surplus, banked RECs) through their generation rates.[75] In the years

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70 *Id.*
71 *Id.*
72 *See* Exh. CalCCA-13 (PG&E response to CalCCA discovery request, acknowledging that a portion of the previously bundled customers that paid generation rates that included an administratively determined value for the RECs forecast to be generated in that year are now departed customers).
73 *See id.* (PG&E response to CalCCA discovery request, acknowledging that a portion of the previously bundled customers that paid generation rates that included an administratively determined value for the RECs forecast to be generated in that year are now departed customers).
74 *See* Exh. CalCCA-16 (PG&E response to CalCCA discovery request, agreeing that the volumes included in the Minimum Retained RPS requirement calculation for PG&E's 2026 ERRA Forecast are for the benefit of customers receiving bundled service in 2026).
75 Evidentiary Hearing Tr. Vol. 1 at 89:7-12.

following 2015, a portion of the customers taking bundled service from PG&E in 2015 have since departed PG&E's bundled service and now take service from CCAs. Fast forwarding to 2026: assuming PG&E uses its 2015 banked RECs towards its bundled customer RPS compliance obligations in 2026, the customers who were bundled in 2015 and remain bundled in 2026 benefit from those banked RECs, as the RECs are retired on those customers' behalf. However, the customers who were bundled in 2015 but are departed in 2026 do not benefit from the retirement of those banked RECs, even though they previously paid for those RECs. Those "Now-Departed" customers must therefore receive value for PG&E's use of the 2015 banked RECs via a credit to the PCIA. This is not a true-up, because neither the payment that bundled customers made in 2015 nor the credit departed customers received in 2015 is trued-up in this scenario. Rather, the customers who paid for RECs in 2015, then departed PG&E's bundled service, are simply made whole, because they finally receive a credit for PG&E's use of those RECs for the benefit of bundled customers, as required by Section 366.2(g) of the Public Utilities Code.

Despite its statements to the contrary, PG&E has implemented this exact accounting practice in prior ERRA cases. Where PG&E has used banked RECs—including RECs generated before 2019—in prior years, it has valued those RECs at the RPS Adder and credited that value to the PCIA vintage corresponding to the year in which the banked RECs were generated. In fact, as recently as its 2025 ERRA Forecast proceeding, PG&E proposed to apply RECs generated in 2018 towards its Minimum Retained RPS obligation, and to credit the 2018 vintage of the PCIA for those RECs at the 2025 Forecast RPS Adder.[76]

[76] *See* Exh. CalCCA-19 (confirming PG&E credited the PCIA indifference calculation for banked RECs generated in 2018 in its 2024 and 2025 ERRA Forecasts); Exh. CalCCA-22 (PG&E testimony proposing to use 2018 banked RECs towards its 2025 Minimum Retained RPS requirement); Exh. CalCCA-23 (confirming PG&E would value 2018 banked RECs used to meet the 2025 minimum retained RPS at the 2025 Forecast RPS Adder).

.[77] CalCCA has consistently supported this valuation practice, because it ensures that the appropriate sets of customers pay for and receive credit for PG&E's use of banked RECs towards bundled customer compliance.[78]

This year, again, PG&E proposes to use banked RECs towards its Minimum Retained RPS requirement—including banked RECs generated in .[79] And, consistent with D.19-10-001 and its practice in prior years, PG&E proposes to value those banked RECs at the 2026 Forecast Adder.[80] But, in a sharp departure from its prior practice, PG&E proposes in this case that customers who paid for banked RECs prior to 2019, but have since departed PG&E's system, should get no credit for those RECs when they are finally used to meet bundled customer compliance requirements.[81] Instead, perplexingly, PG&E proposes to use the RECs for its current bundled customers without crediting any departed customers for PG&E's use of those RECs.[82] This essentially forces Now-Departed customers to subsidize RECs used by today's bundled customers.[83]

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[77] *See* Exh. CalCCA-19 (confirming PG&E credited the PCIA indifference calculation for banked RECs generated in 2018 in its 2024 and 2025 ERRA Forecasts); Exh. CalCCA-20 (PG&E testimony in 2024 ERRA Forecast proceeding, proposing to apply 2018 RECs towards Minimum Retained RPS obligation); Exh. CalCCA-21C); Confidential Tr. Vol. 1 at 110:2-24.

[78] Exh. CalCCA-01 at 40.

[79] Exh. PGE-01E at 8-19 to 8-20.

[80] *Id*. at 8-19.

[81] *Id*.

[82] Exh. PGE-4 at 4-19 to 4-20. CalCCA notes that PG&E's original proposal in this proceeding was to value pre-2019 RECs at the RPS Adder, and credit only the PCIA vintage (2026) corresponding to bundled customers for those RECs, which would effectively result in offsetting credit (to the PCIA) and debit (to ERRA) entries. Exh. PGE-01E at 8-19. In rebuttal testimony, PG&E suggests it could "forgo making the credit entry to PABA and debit entry to ERRA", and simply assign "no ratemaking value" to pre-2019 RECs when used for bundled customer compliance. Exh. PGE-4 at 4-19 to 4-20. Under either approach, departed customers do not receive a credit for PG&E's use of the RECs.

[83] Exh. CalCCA-01C at 36.

As PG&E concedes in response to a CalCCA discovery request in this proceeding, under PG&E's proposal, Now-Departed customers neither have the Pre-2019 banked REC credited to them at the RPS Adder, nor have the REC retired on their behalf—in short, they have paid for RECs that offer them no value.[84] As witness Barry confirmed during the evidentiary hearing:

> Q:[CalCCA Counsel] Okay. So Ms. B[a]rry, let's now consider the customer who was bundled in 20[1]5 and has now departed since then. That customer would have paid for excess RECs in 2015, but would never have received a credit for that REC at the RPS benchmark, correct?
>
> A:[PG&E Witness Barry] That is correct.
>
> Q: And that customer – the same customer – would never have had that same REC retired on her behalf; is that correct?
>
> A: That is correct. [remainder of answer omitted][85]

Witness Barry's admission confirms PG&E's approach violates California law. Public Utilities Code Section 366.2(g) requires that departed load customers receive a credit for the value of any benefits of PCIA resources that remain with bundled service customers, unless those customers are allocated a fair and equitable share of those benefits. Under PG&E's proposal, departed customers who pay for the cost of PG&E's PCIA resources and paid for the banked RECs PG&E now seeks to use would not receive the credit to which they are entitled under Section 366.2(g). PG&E's approach therefore does not comport with the fundamental indifference principle underpinning the PCIA framework, nor does it follow Commission precedent, including D.19-10-001 and its predecessors.

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[84] *See* Exh. CalCCA-15.

[85] Evidentiary Hearing Tr. Vol. 1 at 92:11-21.

To properly credit departed customers for the value of RECs used for current bundled customer compliance, PG&E should apply a credit to the PCIA vintage corresponding to the year the RECs were generated. That credit should be equal to the current value of the banked REC, which is the 2026 Forecast RPS Adder.[86] This accounting would ensure that customers who were bundled at the time the REC was generated, but who have since departed bundled service, receive their share of the value of the RECs now being used for bundled customers.

Below, CalCCA squarely addresses the questions the Commission raises in Scoping Issue 2. Specifically, CalCCA explains that crediting departed load for the value of pre-2019 banked RECs is consistent with D.19-10-001, consistent with PG&E's prior practice, and consistent with sound policy and the indifference principle established in California law. CalCCA also responds to PG&E's testimony on this issue, and explains why the establishment of the PABA true-up in 2019, and the recording of pre-2019 banked RECs in PG&E's WREGIS Retirement Account, are red herrings that should not determine PG&E's valuation of pre-2019 banked RECs. For the reasons described in more detail below, the Commission should reject PG&E's proposal to use banked RECs towards bundled customer compliance without crediting the PCIA vintage corresponding to the year the banked REC was generated.

2. PG&E Proposes to Use Pre-2019 Banked RECs Towards Bundled Customer RPS Compliance Without Crediting The Customers Who Paid For Those RECs.

PG&E explains in testimony that its forecasted RPS-eligible generation in 2026 will fall short of its annual RPS compliance requirement. Therefore, it expects to use [redacted] of

[86] If the RECs were not previously counted as Retained RPS (i.e., Unsold RPS), the PCIA credit should be spread to all vintages based on the PCIA-eligible RPS generation in each vintage. In that way the credit is shared with all customers responsible to pay the cost of PG&E's PCIA-eligible RPS resources. Exh. CalCCA-01C at 37.

banked RECs to meet the minimum Retained RPS requirement.[87] According to its historical net RPS position, PG&E has RECs available that were generated and banked during the years [REDACTED] [REDACTED][88] To cover its minimum Retained RPS requirement in 2026, PG&E proposes to first use RECs generated in and after 2019. Once those Post-2018 Banked RECs are exhausted, PG&E proposes to turn to Pre-2019 Banked RECs. To the extent Post-2018 and Pre-2019 Banked RECs are insufficient to cover PG&E's shortfall, PG&E only then proposes to apply Unsold RPS volumes towards its Minimum Retained RPS requirement, despite having over 3.5 million MWh in Unsold RPS volumes in years following 2019 that currently have zero value and could be used to reduce PG&E's forecast REC shortfall in 2026 and reduce PCIA rates,[89]

To the extent PG&E uses Post-2018 Banked RECs towards its Minimum Retained RPS requirement, consistent with its past practice and the requirements of D.19-10-001 and its predecessors, PG&E will apply the 2026 RPS Adder to value the RECs and apply the credit to the PCIA vintage matching the year the REC was generated. However, if PG&E dips into Pre-2019 Banked RECs (as it anticipates), rather than crediting the PCIA vintage matching the year the REC was generated, PG&E argues that a credit (at the 2026 RPS Adder) should only be given to the most recent PCIA vintage (i.e., 2026).[90] In effect, under PG&E's proposal for Pre-2019 Banked RECs, the PCIA credit and the ERRA debit would fully offset each other and departed load customers would receive zero value for PG&E's use of those RECs towards bundled customer compliance.[91] In other words, PG&E proposes to deny departed load customers their share of the

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[87] Exh. PGE-01E at 8-19 and 8-20, Table 8-4.
[88] *Id.* at Table 8-3.
[89] *Id.* at 8-17.
[90] In rebuttal testimony, PG&E suggests that it would simply assign no value to pre-2019 banked RECs, rather than making offsetting credit (to the 2026 PCIA vintage) and debit (to ERRA) entries. Exh. PGE-4 at 4-19 to 4-20.
[91] *Id.* at 8-19, lines 18-23 and footnote 32.

value of the RECs those very customers paid for. PG&E's proposal departs sharply from its past practice, as PG&E has previously treated Post-2018 and Pre-2019 Banked RECs identically, without any accounting distinction.

The parties do not dispute PG&E's proposal to first use RECs generated in and after 2019 to cover its minimum Retained RPS shortfall in 2026, nor do the parties dispute PG&E's proposal to credit the PCIA vintage corresponding to the year the Post-2018 REC was generated. However, PG&E's proposal to depart from that very same, well-established practice when it comes to Pre-2019 RECs is unsupported by Commission precedent and California law, as this brief explains below.

3. California Law and Over a Decade of Commission Precedent Requires PG&E to Credit Departed Customers at the RPS Adder When It Uses Pre-2019 Banked RECs Towards Bundled Customer RPS Compliance.

As explained above, the indifference framework established in statute requires departed customers pay the net unavoidable costs attributable to the customer,[92] but requires those costs be reduced by the value of any benefits that remain with bundled service customers.[93] Commission decisions have implemented the indifference framework established by statute through a series of decisions stretching over multiple decades. Indeed, a version of the current indifference calculation, including market price benchmarks to reflect IOU portfolio value, has existed for nearly 20 years since D.06-07-030 adopted reforms to the "Customer Responsibility Surcharge" that was the precursor to the PCIA.

Decision 11-12-018 added new components to that calculation to reflect important regulatory and industry changes occurring during the late 2000s.[94] In that decision, the

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92 Pub. Util. Code § 365.2, 366.2(f)(2).
93 Pub. Util. Code § 366.2(g).
94 D.11-12-018.

Commission recognized that the PCIA framework, at the time, recognized only the IOUs' cost of renewable resources in the calculation of the Indifference Amount, but did not account for the market value of renewable resources via the Market Price Benchmark.[95] The Commission therefore created an RPS "Adder" to the Market Price Benchmark,[96] and required the IOUs to apply that Adder to the renewable resources in the IOUs' portfolios.[97] Following D.11-12-018 therefore, the indifference calculation appropriately reflected the incremental RPS value of RPS-eligible generation retained by bundled service customers via the RPS Adder. That means the RECs PG&E forecasted to be delivered in each forecast year were retained at the RPS Adder in that year and credited to the indifference calculation.[98]

Decision 18-10-019 and D.19-10-001 modified the PCIA framework by, among other things, adding a true-up to the PABA, and by creating "Unsold" and "Sold" RPS categories within the IOUs' RPS-eligible generation. Decision 19-10-001, specifically, established a methodology for calculating the Forecast RPS value and true up for each category of RPS product in the IOUs' portfolios (Retained, Sold and Unsold).[99] Decision 19-10-001, however, left intact the fundamental requirement, created by D.11-12-018, that for RPS-eligible resources retained by bundled customers, the indifference calculation must reflect the incremental RPS value of RPS-eligible resources retained by bundled customers. In fact, D.19-10-001 expressly requires all RECs forecasted to be used towards bundled customer compliance in any given year to be valued at the

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[95] *Id*. at 10.

[96] Whereas the Market Price Benchmark in effect at the time included an "adder" that reflected the cost of resource adequacy, it did not yet include an RPS Adder.

[97] *See* D.11-12-018 at 10-11 ("The MPB used to determine the PCIA is multiplied by the entire amount of RPS-eligible energy in the IOU's portfolio.").

[98] *See* Exh. CalCCA-14.

[99] D.19-10-001 at OP3, Attachment B.

RPS benchmark and credited to the PCIA.[100] That requirement applies to all Forecast Retained RPS; D.19-10-001 does not draw any distinction between the treatment of different REC volumes—pre-2019 banked RECs, post-2018 banked RECs, or Unsold REC volumes—when those RECs are ultimately applied towards bundled customer compliance. In other words, irrespective of when a REC was generated, and irrespective of whether any customer previously paid for that REC, D.19-10-001 requires that REC be valued at the benchmark applicable in the year it is retired. Nothing in D.19-10-001 exempts pre-2019 banked RECs from being valued at the benchmark. This fact is unsurprising, because once PG&E retains a REC for the benefit of bundled customers, California law demands departed load receive its share of the value of that REC.[101]

Where D.19-10-001 creates a dividing line between 2018 and 2019 is in its treatment of Unsold RPS. In D.19-10-001, the Commission departed from its prior practice of requiring the valuation of all RECs in the year they are generated, and assigned Unsold RECs zero value for PCIA ratemaking purposes provided those RECs were generated after December 31, 2018.[102] That means no customer pays for post-2018 Unsold RECs, which are valued at zero dollars, until those RECs are used or sold in a subsequent year (at which time, per D.19-10-001, those RECs are valued at the RPS Adder).

PG&E's core argument in support of its proposal to deny departed load the value of pre-2019 banked RECs is that D.18-10-019 and D.19-10-001 fundamentally altered the PCIA framework, creating a disjuncture that permits different treatment for pre-2019 and post-2018 banked RECs. Further, according to PG&E witness Barry, the PCIA rates set between 2010 and

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[100] *Id*. at Attachment B.
[101] Pub. Util. Code § 366.2(g).
[102] D.19-10-001 at 35; OP3b.

2018 "were fully litigated in the ERRA Forecast proceedings" between those years, and therefore a credit to departed load for PG&E's use of pre-2019 banked RECs would result in an impermissible "partial refund" to those customers.[103]

PG&E's argument is hollow. As discussed above, D.18-10-019 and D.19-10-001 introduced a PABA true-up, which meant, starting in 2019, PCIA rates based on forecasts would be trued-up to actuals the following year.[104] The fact that a PABA true-up did not exist prior to 2019, however, has no bearing on the question of the proper valuation of pre-2019 banked RECs. As PG&E acknowledges, prior to D.19-10-001, all PCIA-eligible RPS generation was recognized as either being sold to third parties or retained by then-bundled customers and valued at the RPS Adder. [105] Customers who were bundled at the time therefore paid for Retained RECs, including those RECs that were surplus to PG&E's bundled customer compliance requirement.[106] In a similar vein, in years *since* 2019, PG&E's bundled customers have continued to pay for all Retained RECs at the RPS Adder, including those RECs that are surplus to PG&E's bundled customer compliance requirement.[107] A portion of the customers who were bundled at the time PG&E generated surplus RECs have departed PG&E's bundled service before PG&E could use those surplus RECs towards bundled customer compliance. Basic logic and fairness demands those customers receive value for the RECs they previously paid for. The fact that a true-up did not exist prior to 2019 is not material, because valuing banked RECs at the RPS Adder in the year those RECs are used does not constitute a true-up of a past generation rate. Rather, valuing those banked

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[103] Exh. PGE-4 at 4-8.
[104] D.18-10-019 at OP 8; D.19-10-001 at OP3, OP4.
[105] Evidentiary Hearing Tr. Vol. 1 at 89.
[106] *Id*.
[107] *See* Exh. CalCCA-17 (explaining that all RECs generated in 2021 and 2022 were retained at the applicable MPBs).

RECs at the current RPS Adder, and crediting the vintage corresponding to the year the REC was originally paid for, makes customers whole, because it ensures all customers—bundled and Now-departed—who originally paid for the REC receive its value.

PG&E's claim that CalCCA's proposal is a true-up is also misleading—the pre-2019 banked RECs are not being trued up. Rather, Now-Departed customers are receiving a credit at the MPB for PG&E's use of those banked RECs <u>for the first time.</u> The utility emphasizes that D.19-10-001 and D.18-10-019—companion decisions that collectively significantly altered the PCIA framework—introduced a PABA true-up effective in 2019. As PG&E states in rebuttal testimony, "In Phase 1, Track 2 [of the 2017 PCIA Rulemaking, R.17-06-026], the PCIA calculation methodology was revised by D.18-10-019, which included updated accounting treatment through the adoption of the [PABA] in order to effectuate a going-forward true-up of portfolio costs and value, and was effective *January 1, 2019*."[108] Decision 19-10-001, issued in Phase 2 of the 2017 PCIA Rulemaking, "dealt with the method, data and process requirements for the forecast and true up of the Market Price Benchmarks (MPB) to be used in determining the PCIA rate",[109] and states, "[t]he methods adopted in this Decision apply to RECs generated commencing January 1, 2019, and going forward."[110] However, the fact that D.18-10-019 and D.19-10-001 introduced a PABA true-up (including a true-up of RPS value in the PCIA) effective in 2019 is neither controversial nor in dispute here. To be clear: CalCCA does not request the Commission direct a *true-up* of RECs generated and used for bundled customer compliance prior to 2019. What D.19-10-001 requires, however, is that when a REC—banked or otherwise—is used for bundled customer compliance, that REC must be valued at the RPS Adder for the Forecast year. This concept of

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108 Exh. PGE-4 at 4-3 (emphasis *sic*).
109 *Id*.
110 D.19-10-001 at Finding of Fact (FOF) 8.

crediting RECs that are used for bundled customer compliance is not new; it was established in D.11-12-018. The introduction of the PABA true-up in 2019 does not in any way permit PG&E to ignore a framework that has been in place since 2011 and use pre-2019 RECs for bundled customer compliance for free, without applying any credit to departed load.

PG&E's claim that CalCCA's methodology would require the Commission to "undo" previously litigated rates is also meritless, because the PCIA framework would accommodate a credit to pre-2019 PCIA vintages in much the same way it routinely accommodates credits to post-2018 vintages. For instance, in this proceeding, PG&E proposes a credit to the ████ vintage of the PCIA to account for its use of ████ banked RECs. Applying that credit does not require PG&E to "undo" previously litigated ████ PCIA rates. And, notably, PG&E does not claim those credits would undo previously litigated PCIA rates.

In sum, D.18-10-019 and D.19-10-001 undoubtedly made significant changes to the PCIA framework, but the changes those decisions introduced—including the PABA true-up—do not help PG&E's argument with respect to pre-2019 banked RECs. Nothing about the ratemaking framework that existed prior to 2019 justifies PG&E's attempt to deny departed load the credits they are due when bundled customers use pre-2019 banked RECs for compliance purposes.

PG&E also misconstrues the language in D.19-10-001. PG&E's witness Barty states: "[t]he ratemaking modifications adopted in D.19-10-001 were prospective and applied to RECs generated on or after January 1, 2019."[111] Here, PG&E misses the distinction between Unsold RPS and Forecast Retained RPS. In essence, PG&E argues that by assigning post-2018 Unsold RECs zero value, the Commission created a *de facto* January 1, 2019 "effective date" for the valuation of banked RECs at the MPB for the year in which those RECs are applied towards a utility's

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[111] Exh. PG&E-4 at 4-2:9-10.

Minimum Retained RPS. Nothing in the *dicta*, findings of fact, conclusions of law or ordering paragraphs of D.19-10-001 supports PG&E's logical leap. Decision 19-10-001 indeed established a January 1, 2019, effective date for assigning Unsold RECs zero value.[112] Contrary to PG&E's argument, however, nothing in D.18-10-019 or D.19-10-001 establishes a parallel January 1, 2019, "effective date" with respect to the valuation of banked RECs used to meet the utility's Minimum Retained RPS requirement.

Curiously, despite taking the position that D.19-10-001 only applies to RECs generated in or after 2019, PG&E nevertheless proposes to value Pre-2019 RECs at the 2026 Forecast RPS Adder. PG&E's proposed methodology appears to concede that D.19-10-001 requires all RECs forecasted to be used towards bundled customer compliance in any given year be valued at the RPS benchmark, whether those RECs were generated Pre-2019 or Post-2018 (consistent with CalCCA's interpretation of D.19-10-001). Where PG&E's methodology goes wrong, however, is where PG&E applies a credit to only the latest PCIA vintage (such that only bundled customers receive that credit). That aspect of PG&E's proposal has absolutely no basis in D.19-10-001. Moreover, crediting 2026 bundled customers for RECs purchased by PG&E's bundled customers several years ago is utterly illogical, because those two sets of bundled customers are not the same.

4. PG&E Has Previously Credited Departed Customers at the RPS Adder Each Time It Has Used Pre-2019 Banked RECs Towards Bundled Customer RPS Compliance.

PG&E's proposal to use pre-2019 banked RECs towards bundled customer compliance while denying departed load their share of the value of those RECs is a striking departure from its prior practices. In testimony supporting its 2024 ERRA Forecast Application, filed on May 15, 2023, PG&E proposed to use RECs generated and banked in 2018 to help cover a shortfall towards

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[112] D.19-10-001 at 28, footnote 22.

its Minimum Retained RPS obligation in 2024.[113] [redacted]

[redacted].[114] In this manner, PG&E conveyed customers departing after 2018 their share of the value of banked RECs they paid for in 2018, when they were bundled customers.

PG&E repeated the same practice in 2025. In its rebuttal testimony supporting its 2025 ERRA Forecast Application, PG&E proposed to use RECs generated and banked in 2018 to help cover a shortfall towards its Minimum Retained RPS obligation in 2025.[115] In response to CalCCA discovery in that case, PG&E confirmed it would value those 2018 RECs at the 2025 Forecast RPS Adder and apply that credit to the year in which the RECs were generated: 2018.[116] Thus, in both 2024 and 2025, PG&E proposed to use 2018 banked RECs towards bundled customer compliance obligations, valued those RECs at the RPS adder applicable in the year the banked REC was to be used, and credited the 2018 vintage of the PCIA with that value. In each case, CalCCA supported PG&E's approach.

In the instant proceeding, PG&E attempts to walk back its past practice by claiming that RECs generated in 2018 were somehow banked in 2019. Based on this fiction, PG&E claims "[b]undled customers have not paid for the use of *pre-2019 banked RECs* in prior ERRA forecast proceedings."[117] The Commission should ignore PG&E's acrobatics. As PG&E concedes, "[h]istorically, RECs generated in a given year are considered banked in the same year."[118] That means surplus RECs generated in 2016 are banked in 2016. Surplus RECs generated in 2017 are

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113 Exh. CalCCA-20.
114 Exh. CalCCA-21C.
115 Exh. CalCCA-22.
116 Exh. CalCCA-23; *see also* Evidentiary Hearing Tr. Vol. 1 at 113-114.
117 Exh. PGE-4 at 4-13.
118 Exh. CalCCA-19.

banked in 2017. And surplus RECs generated in 2018 are banked in 2018. During cross examination, even PG&E's witness disavowed PG&E's untenable legal position, and acknowledged that RECs generated in 2018 should be considered banked in 2018:

> Q: [CalCCA Counsel] Is it your position that RECs generated in 2018 are banked in 2019?
>
> A: [PG&E witness Barry] My personal opinion is that RECs generated in 2018 should be classified as RECs banked in 2018.[119]

The record unequivocally demonstrates that PG&E has previously used RECs banked prior to 2019 towards its Minimum Retained RPS obligation, valued those RECs at the RPS Adder applicable to the year those RECs were used, and credited the PCIA vintage corresponding to the year in which the REC was generated and banked. PG&E's proposal in this proceeding, therefore, is a clear departure from that prior, Commission-approved practice.

PG&E further stretches to argue that it only credited the 2018 vintage of the PCIA for 2018 banked RECs because it was directed to do so by D.23-12-022, which classified those RECs as "banked in 2019."[120] But PG&E's argument falls apart under scrutiny. Decision 23-12-022 was issued in December of 2023. PG&E's proposal to use 2018 RECs towards its 2024 Minimum Retained RPS requirement, value those RECs at the 2024 Forecast Adder, and credit the 2018 vintage of the PCIA with that value, predated D.23-12-022 by seven months—PG&E made that proposal in its testimony filed in May of 2023.[121] PG&E may no longer wish to stand by its prior practice, but the Commission should disregard PG&E's attempts to cast that prior practice as consistent with its proposal in this proceeding.

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[119] Evidentiary Hearing Tr. Vol. 1 at 107.
[120] Exh. CalCCA-19.
[121] Exh. CalCCA-20

5. Crediting Departed Customers at the RPS Adder When PG&E Uses Pre-2019 Banked RECs Towards Bundled Customer RPS Compliance Is Both Logical and Fair.

As explained above, D.19-10-001 and its predecessors require PG&E to value pre-2019 banked RECs at the applicable RPS Adder in the year those RECs are used towards bundled customer compliance, and credit the PCIA vintage corresponding to the year those RECs were generated. But even if D.19-10-001 were ambiguous (and it is not), valuing pre-2019 banked RECs in this manner also produces a logical and fair outcome. Importantly, applying a credit to the PCIA vintage corresponding to the year the pre-2019 banked REC was generated does not result in double-compensation *to* any customer, nor does it result in double-payment *from* any customer. Rather, applying credit to the PCIA vintage corresponding to the year the Pre-2019 Banked REC was generated and banked results in a net payment from today's bundled customers to previously bundled, but "Now-Departed" customers for the portion of the banked RECs those "Now-Departed" customer previously paid.[122]

Table 1 below illustrates this transfer using numbers from PG&E's service territory. In each year since 2013, additional customer load in PG&E's service territory has departed bundled service. Table 1 uses the sales forecast in the current proceeding to distinguish PG&E's system sales by bundled vs unbundled service and customer vintage. According to PG&E's vintage sales data, roughly 87 percent of PG&E's system received bundled service in 2013. In 2026 PG&E projects approximately 32 percent of its system will receive bundled service.[123]

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[122] Exh. CalCCA-01C at 47.
[123] *Id*. at 48.

Table 1: PG&E 2026 System Sales by Customer Vintage (MWh)[124]

PCIA Vintage	Bundled	Departed	Total System	% Bundled
2013	68,447,069	10,039,076	78,486,145	87%
2014	67,534,534	10,951,611	78,486,145	86%
2015	65,639,298	12,846,847	78,486,145	84%
2016	65,393,001	13,093,144	78,486,145	83%
2017	58,758,778	19,727,367	78,486,145	75%
2018	46,453,885	32,032,260	78,486,145	59%
2019	36,678,603	41,807,542	78,486,145	47%
2020	34,492,530	43,993,615	78,486,145	44%
2021	31,225,581	47,260,564	78,486,145	40%
2022	29,030,908	49,455,237	78,486,145	37%
2023	28,624,970	49,861,175	78,486,145	36%
2024	28,176,001	50,310,144	78,486,145	36%
2025	28,139,821	50,346,324	78,486,145	36%
2026	25,055,466	53,430,679	78,486,145	32%

From 2013 through 2022, customers receiving bundled service at the time RECs were generated paid for the RECs through generation rates. As shown in Table 2 below, comparing the current bundled sales volume to the bundled sales in years going back to 2013 demonstrates that customers who received bundled service in previous years, but have since departed, paid for a significant portion of PG&E's banked RECs each year.[125]

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124 *Id.*

125 *Id.*

Table 2: Current Bundled Sales Versus Bundled Sales in Prior Years[126]

PCIA Vintage	Current Bundled MWh	Previously Bundled/Now Departed MWh	Total Bundled MWh by Vintage Year	% Current Bundled	% Previously Bundled
2013	25,055,466	43,391,602	68,447,069	37%	63%
2014	25,055,466	42,479,067	67,534,534	37%	63%
2015	25,055,466	40,583,831	65,639,298	38%	62%
2016	25,055,466	40,337,535	65,393,001	38%	62%
2017	25,055,466	33,703,312	58,758,778	43%	57%
2018	25,055,466	21,398,419	46,453,885	54%	46%
2019	25,055,466	11,623,137	36,678,603	68%	32%
2020	25,055,466	9,437,064	34,492,530	73%	27%
2021	25,055,466	6,170,115	31,225,581	80%	20%
2022	25,055,466	3,975,441	29,030,908	86%	14%
2023	25,055,466	3,569,503	28,624,970	88%	12%
2024	25,055,466	3,120,535	28,176,001	89%	11%
2025	25,055,466	3,084,355	28,139,821	89%	11%
2026	25,055,466	-	25,055,466	100%	0%

Now-departed customers paid for the portion of RECs in each year as listed under "% Previously Bundled" in the table above (the right-most column).[127] For example, now-departed customers paid 63 percent of the cost of the RECs generated in 2013, including 63 percent of the RECs that were banked and are now available to be used for compliance on behalf of current bundled customers.[128] Similarly, now-departed customers paid 57 percent of the cost of RECs generated in 2017. If the banked RECs now needed for Retained RPS requirements were already paid for by customers in previous years, the banked REC credit should be applied to the PCIA vintage corresponding to the year the RECs were generated. In this way, customers who were bundled at the time the RECs were generated, but who have since departed bundled service, would receive credit for the value of the RECs now being used for current bundled customers.[129]

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[126] *Id.*
[127] *Id.* at 49.
[128] *Id.*
[129] *Id.*

That is why crediting the PCIA for the value of banked RECs that were paid for by bundled customers in prior years does not result in a double charge to today's bundled customers.[130] Rather, current bundled customers would only be charged for the banked RECs previously paid for by now-departed customers.[131] The now-departed customers receive credit for the value of RECs counted as Retained RPS on behalf of current bundled customers, leaving the now-departed customers indifferent relative to current bundled customers.[132] To be clear, those departed customers do not receive *all* of the value of banked RECs that were paid for by then-bundled customers—they receive only an amount proportional to the share they paid for.[133] The Commission has employed this type of policy – crediting customers through the PCIA for refunds or credits for which they are owed – in numerous places in ERRA proceedings.[134]

The following figures illustrate the payments and credits that should be recognized if RECs generated and banked in 2013 in PG&E's service territory are needed to meet bundled customers' RPS compliance obligations in 2026.

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[130] *Id*. at 50.
[131] *Id*.
[132] *Id*.
[133] *Id*.
[134] For example, in D.22-01-023, the Commission directed that prior year under- or over-recovery balances in IOU ERRA balancing accounts should be transferred to the most-recent vintage subaccount of PABA to facilitate recovery or refund to customers.

Figure 6: Banked RECs are Generated and Paid For in 2013[135]

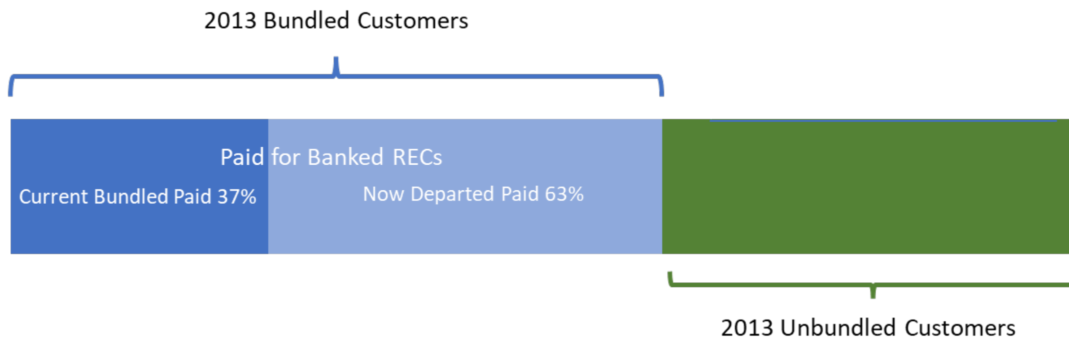
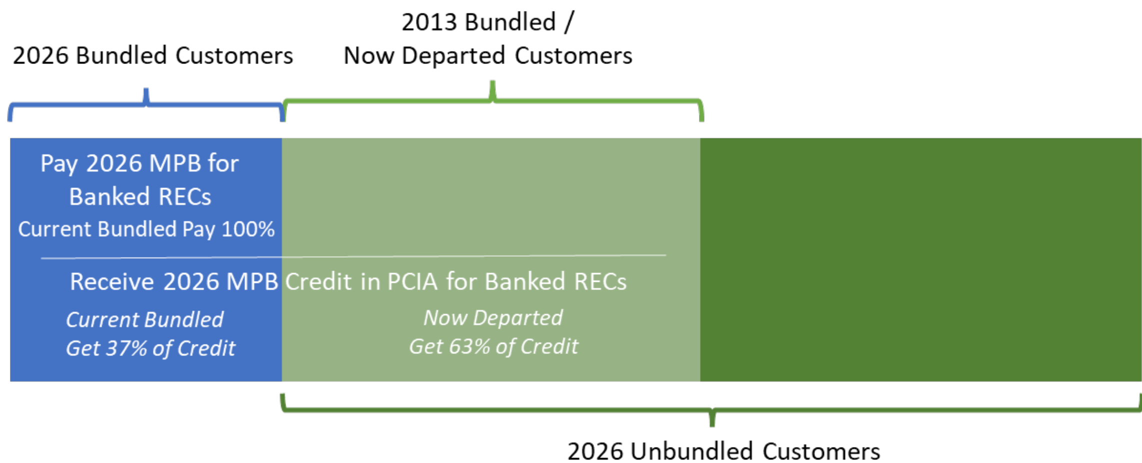


Figure 6 shows that all bundled customers in 2013, including now-departed customers that left PG&E's service after 2013 (the light blue portion above), paid a portion of the cost of the RECs that were banked in 2013. An offsetting credit was applied in the PCIA and shared between all bundled and unbundled customers.

Figure 7: Banked RECs are Used for Retained RPS in 2026[136]



Customers who were bundled during 2013 and have since departed PG&E's bundled service can no longer use the banked RECs.[137] Figure 7 demonstrates that if RECs banked in 2013 are used

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[135] Exh. CalCCA-01C at 50.

[136] *Id.* at 51.

[137] *Id.*

for RPS compliance in 2026, current bundled customers (the dark blue portion) should pay the MPB for those RECs, and the value of the RECs should be credited to PCIA vintage 2013.[138] By crediting PCIA vintage 2013, the credit is shared by today's bundled customers and unbundled customers who received bundled service in 2013, but not by customers who departed prior to 2013.[139] Customers who departed after 2013 (the light green portion) are credited at today's MPB at the current value of the RECs, and they receive the same percentage of the credit as the percentage of the total cost they paid in 2013.[140]

Bundled customers also receive a percentage of the Retained RPS credit at the current value of the RECs – the same percentage of the total cost for the RECs those customers paid in 2013.[141] None of the customers that were already departed in 2013 would receive an additional "double" credit.[142] Those customers already received a credit in 2013 and it would not be fair to credit them again in 2025.[143] However, for now-departed customers that were bundled customers in 2013, crediting the value of banked RECs to the PCIA using the 2026 RPS Adder ensures that those customers are indifferent to bundled customers' use of banked RECs for which now-departed customers paid for but can no longer use.[144]

Because bundled and unbundled customers all pay a share of the PCIA revenue requirement based on their vintaged load share, credits to the PCIA are also shared between bundled and departed load customers.[145] The following quantitative example demonstrates the net

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138 *Id.*
139 *Id.*
140 *Id.*
141 *Id.*
142 *Id.* at 52.
143 *Id.*
144 *Id.*
145 *Id.*

charge to bundled customers for using banked RECs, after considering their share of the PCIA credit.[146] If PG&E needs 100 GWh of Banked RECs to count toward its 2026 RPS compliance target and those banked RECs were generated in 2013, PG&E should credit PCIA vintage 2013 for the value of the banked RECs using the 2026 RPS Adder.[147] Applying the filed RPS Adder MPB of $71.24/MWh, the PCIA vintage 2013 credit would be $7.1 million.[148] As shown in Table 3 below, bundled customer generation rates would include a Retained RPS charge of $7.1 million, but they would also receive a $2.6 million share of the credit to the PCIA.[149] The resulting $4.5 million net charge represents the value paid to departed load customers in exchange for use of the banked RECs from 2013.[150]

Table 3: Banked REC Example – Net Charge to Bundled Customers[151]

Item	Amount
RPS Adder MPB ($/MWh)	$71.24
Banked RECs Used (GWh)	100
Banked REC Value Credit to PCIA ($000)	($7,124)
Departed Load Share ($000)	($4,539)
Bundled Load Share ($000)	($2,585)
Bundled Charge to ERRA ($000)	$7,124
Net Charge to Bundled Customers ($000)	**$4,539**

Furthermore, as discussed above, the credit to the PCIA should be valued using the RPS Adder in the year the RECs are used for bundled customer compliance.[152] When the banked RECs were

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146 *Id*.
147 *Id*.
148 *Id*.
149 *Id*.
150 *Id*.
151 *Id*. at 53.
152 *Id*.

paid for through the PCIA, a net credit was conveyed to unbundled customers at the time.[153] But for bundled customers, the charge and credit for their share of the RECs were offsetting and the RECs were stored for later use.[154] When used, current bundled customers will extract the contemporaneous value of the RECs by using them for compliance.[155] Now departed customers should also receive the contemporaneous value of the REC through the PCIA credit priced at the current RPS Adder.[156] And, to ensure that customers are not double-credited for RECs generated in a prior year, the value of Pre-2019 Banked RECs should be credited to PCIA vintages based on the year the RECs were generated.[157]

Table 10 in CalCCA witness Dickman's testimony provides details of PG&E's REC bank, showing annual deposits and withdrawals since 2013, including PG&E's projection for 2026.[158] For the 2026 ERRA Forecast, PG&E projects it will need to use banked RECs from [redacted] to meet its minimum RPS requirement.[159] Based on the accounting in Table 10 in witness Dickman's testimony, a total credit of [redacted] should be included as a reduction to the 2026 Indifference Amount forecast to reflect the value of banked RECs needed in 2026.[160] PG&E's testimony discusses applying the current RPS Adder to the Post-2018 Banked RECs generated in [redacted] and applying that credit to the [redacted] PCIA vintage. PG&E must also apply this treatment to the Pre-2019 Banked RECs from [redacted][161] Table 11 in CalCCA witness Dickman's

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153 *Id*.
154 *Id*.
155 *Id*.
156 *Id*.
157 *Id*.
158 *Id*. at 53-54.
159 *Id*. at 54.
160 *Id*.
161 *Id*.

testimony[162] breaks down the total credit into the PCIA vintages corresponding to the banked RECs used each year and the bundled and departed load customers' share of these credits.[163] As shown in that table, the [redacted] credit for 2026 would be allocated between PCIA Vintages [redacted] according to the number of RECs used from each generation year.[164]

In contrast, PG&E proposes in its testimony to credit the value of the Pre-2019 Banked RECs to PCIA vintage 2026 and to credit the value of the Post-2018 Banked RECs to the PCIA vintage year in which the RECs were generated.[165] Table 12 in CalCCA witness Dickman's testimony[166] shows the REC credit share by vintage under PG&E's proposal.

Correcting the vintage assignment for Pre-2019 Banked RECs increases the credit to departed load customers by [redacted] compared to PG&E's proposal.[167] PG&E should credit the PCIA vintage years in which all Banked RECs (Pre-2019 Banked RECs and Post-2018 Banked RECs) were generated, while valuing them at the RPS Adder of the year in which the RECs are used to ensure departed load customers are properly credited for resources they paid for but are used by bundled customers.[168]

6. The Fact that Pre-2019 Banked RECs Are Held In PG&E's WREGIS Retirement Account Does Not Prevent PG&E From Crediting Departed Customers at the RPS Adder When PG&E Uses Pre-2019 Banked RECs Towards Bundled Customer RPS Compliance.

In rebuttal testimony, PG&E witness Barry devotes significant ink to describing the recording of PG&E's banked RECs to the Western Renewable Energy Generation Information

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162 *Id*. at 55.
163 *Id*. at 54.
164 *Id*. at 54-55.
165 *Id*. at 55.
166 *Id*. at 56.
167 *Id*.
168 *Id*.

System (WREGIS).[169] Witness Barry states the pre-2019 banked RECs held in WREGIS may be used by PG&E bundled customers to meet bundled customer RPS compliance obligations, but those RECs are not tradable or transferable, and therefore "this eliminates the market value of the banked RECs."[170] Witness Barry attempts to contrast the value of those pre-2019 banked RECs with the value of RECs in PG&E's current Active WREGIS account, which can be transferred or sold more easily.

Witness Barry's discussion of PG&E's WREGIS Retirement Account is a red herring. As PG&E acknowledged in response to CalCCA's discovery, if PG&E were in a short RPS compliance position and did not have pre-2019 banked RECs available, it would *need to procure RPS-eligible products* on the market to meet its compliance requirements.[171] It follows, therefore, that the value of pre-2019 banked RECs to bundled customers in 2026 is the value of an avoided market purchase of RPS-eligible products. Moreover, as PG&E confirmed in response to CalCCA's discovery, PG&E has previously applied banked RECs in its WREGIS Retirement Account towards its Minimum Retained RPS requirement.[172] In PG&E's 2025 ERRA Forecast proceeding, PG&E applied 2018 RECs towards its Minimum Retained RPS requirement,[173] valued those RECs at the 2025 Forecast RPS Adder, and credited the 2018 vintage of the PCIA for those RECs,[174] even though those RECs were in PG&E's WREGIS Retirement Account at the time. Thus, the fact that PG&E's pre-2019 banked RECs are in PG&E's WREGIS Retirement Account does not in any way preclude PG&E from using those RECs towards bundled customer compliance

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169 Exh. PGE-4 at 4-20 to 4-22.
170 *Id*. at 4-21 to 4-22.
171 Exh. CalCCA-26.
172 Exh. CalCCA-27.
173 *Id*.
174 Exh. CalCCA-23.

obligations in 2026, valuing those RECs at the 2026 Forecast RPS Adder, and crediting that value to the PCIA vintage corresponding to the year in which the banked RECs were generated. The Commission should direct PG&E to take these exact steps here.

B. THE COMMISSION SHOULD REJECT PG&E'S RA SOD PROPOSALS (SCOPING ISSUE 3)

Scoping Issue 3 asks: "Is PG&E's proposal to modify its Resource Adequacy (RA) valuation methodology for Power Charge Indifference Adjustment (PCIA) ratemaking purposes to account for the Slice-of-Day (SoD) methodology reasonable? If not, is there another methodology that should be applied instead on an interim basis?" PG&E makes two proposals to modify its RA valuation methodology for PCIA ratemaking purposes—one in its direct testimony, and one in its rebuttal testimony. Neither methodology PG&E proposes is reasonable—in particular with respect to its treatment of the RA value associated with PG&E's battery resources. The methodology PG&E proposes in direct testimony would effectively assign battery resources zero value—an absurd outcome that fails to comport with the market reality. Batteries are not free; in fact, they offer significant capacity value. The methodology PG&E proposes in rebuttal testimony no longer assigns battery resources zero value, but it appears to be designed to "compromise" with CalCCA, rather than produce a methodology that reasonably estimates the RA value of PCIA resources. And, again, although PG&E's revised methodology assigns batteries more capacity value than PG&E's original RA SoD proposal did, the revised methodology does not appear to reflect the value of storage resources in the market, including PG&E's own valuation of those resources when it evaluates procurement opportunities for bundled customers.

The Commission should reject both of PG&E's proposed RA valuation methodologies and direct PG&E to maintain its existing approach to valuing its RA capacity until this issue is more carefully and holistically evaluated in the PCIA OIR. The implementation of the SoD framework

for RA compliance likely impacts both the price and quantity terms used to value PG&E's PCIA portfolio, and each of those terms can be examined in the PCIA OIR. In contrast, PG&E's proposal here considers *only* a modification to the quantity used to calculate RA value—an incomplete view (similar to PG&E's incomplete proposal to look at only the price side of the equation in last year's ERRA Forecast case) that will lead the Commission to a suboptimal solution. However, if the Commission is inclined to adopt an interim change to PG&E's existing RA valuation approach in this proceeding, it should adopt SCE's Interim SoD Method.

1. Issue Introduction and Executive Summary

PG&E must calculate the value of its capacity portfolio to determine the PCIA revenue requirement. Under the Commission-approved PCIA methodology, a single RA Adder (*i.e.*, price) is multiplied by the amount of Retained RA capacity (*i.e.*, quantity) used for bundled customer RA compliance to determine the value of the capacity retained by the IOU (*i.e.*, price * quantity = value). Currently, the RA Adder and Retained RA capacity are each a single number representing the average price and quantity of RA across the entire year, respectively.[175]

In D.22-06-050,[176] the Commission adopted a 24-hour SoD framework that transitions the RA program away from a single Net Qualifying Capacity (NQC) requirement in the peak hour each month. Instead, the new framework requires each LSE to demonstrate sufficient capacity to satisfy its specific gross load profile, including the planning reserve margin, in all 24 hours on the CAISO's "worst day" in each month.[177] In D.23-04-010,[178] the Commission approved additional implementation details for the SoD framework and affirmed that it intended to move forward with

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175 Exh. CalCCA-01C at 10.
176 D.22-06-050.
177 Exh. CalCCA-01C at 10-11.
178 D.23-04-010.

SoD compliance in 2025.[179] In D.24-06-004,[180] the Commission confirmed the start of the SoD framework would be in 2025. However, to date, the Commission has not issued any decisions or determinations regarding whether, or the manner in which, the PCIA template and framework should change in response to the new SoD framework.[181]

Following these changes to the Commission's RA program, PG&E proposes to significantly change its approach to calculating the value of its capacity portfolio.[182] While PG&E advances two significantly different proposals in its direct and rebuttal testimony, at a high level, PG&E's proposed RA valuation methodologies focus squarely on the *quantity* component of the Retained RA equation, while setting the *price* component to the side. PG&E's proposed methodologies would change the calculation of the Retained RA quantity by translating hourly SoD RA volumes into monthly values, which are then averaged across all months to produce a single average RA quantity (to which a price—the RA MPB—is applied).[183] The upshot of PG&E's proposed methodologies is a significant reduction to the quantity of RA capacity used to calculate Retained RA in the PCIA calculation, thereby reducing the value of PG&E's capacity portfolio, increasing the Indifference Amount and requiring unbundled customers to pay a larger portion of the PCIA portfolio's costs.[184]

To be clear, the implementation of the SoD framework is a significant change to the Commission's RA compliance program and that change may have implications for the PCIA. Those implications merit careful consideration by the Commission in the PCIA Rulemaking, not

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[179] Exh. CalCCA-01C at 11.
[180] D.24-06-004.
[181] Exh. CalCCA-01C at 11.
[182] *Id*.
[183] Exh. PGE-01E at 8-14.
[184] Exh. CalCCA-01C at 11.

in this expedited ERRA Forecast proceeding, the purpose of which is to establish procurement revenue requirements for 2026 ratesetting purposes by implementing existing Commission decisions. Indeed, as PG&E acknowledges, changes to the valuation of RA for PCIA ratemaking purposes resulting from the implementation of the SoD framework may soon be considered in the PCIA OIR.[185] There is simply no compelling reason for the Commission to adopt a departure from PG&E's existing RA valuation methodology in this proceeding, only to again consider changes to that methodology in the PCIA OIR.

On the contrary, there are several compelling reasons for the Commission to <u>avoid</u> adopting any change to PG&E's current RA valuation methodology in this proceeding. Namely, adopting a change to PG&E's RA valuation methodology in this proceeding would deny the Commission the benefit of the input of the many stakeholders that are absent from this proceeding; result in inconsistent treatment of ratepayers in different service territories; deny the Commission the benefit of the work that will be done in the PCIA Rulemaking to understand the impacts of SoD on the market; and consider only one half of the RA value equation (quantity) while ignoring the other (price), leading to a suboptimal solution.

Importantly, the Commission should under no circumstances adopt PG&E's proposed modifications to its RA valuation methodology (on an interim basis or otherwise) because PG&E's proposals are rife with flaws, in particular with respect to their treatment of battery resources. The Commission should reject both of PG&E's proposed RA valuation methodologies and direct PG&E to maintain its existing approach to valuing its RA capacity until the Commission more carefully and holistically evaluates this issue in the PCIA OIR. However, if the Commission is

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[185] Application at 26.

inclined to adopt an interim change to PG&E's existing RA valuation approach in this proceeding, it should adopt SCE's Interim SoD Method, which this brief describes in more detail below.

2. PG&E's Original RA SoD Proposal Results In a Near-zero RA Quantity for Storage

The multi-step RA valuation methodology PG&E proposes in direct testimony (PG&E's "original RA SoD proposal") is highly complex. PG&E proposes to calculate a weighted average of its hourly RA position with different treatments for different resource types.[186] Baseload resources are assigned a flat profile, meaning the same amount of capacity (i.e., NQC) is counted in every hour (varying by month).[187] PG&E's baseload treatment applies to natural gas, hydro, geothermal, biomass, biogas, and long-duration energy storage including pumped storage.[188] Wind and solar resources are assigned capacity values that vary by hour and month based on an "exceedance" methodology.[189] For battery storage resources, PG&E proposes to develop an optimized hourly charging and discharging profile and then average all hours together.[190]

PG&E explains in testimony that it develops an hourly bundled system RA position before factoring in energy storage and then determines the optimal charge and discharge profile to meet RA compliance needs while satisfying the SoD charging sufficiency requirement.[191] PG&E compares its bundled customer load profile to the RA available from its generation resources and develops charging and discharging profiles of its storage resources to determine what non-storage resources can be used to charge its storage resources at different times of the day and which hours are projected to have excess supply that will either be sold to third parties or remain as Unsold

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186 Exh. CalCCA-01C at 13.
187 *Id.*
188 Exh. PGE-01E at 4-11.
189 *Id.*
190 Exh. CalCCA-01C at 13.
191 Exh. PGE-01E at 5-8.

RA.[192] PG&E proposes to determine the average annual Retained RA quantity by summing up the storage-adjusted hourly RA position, applying hourly weighting factors from the California Energy Commission's (CEC) hourly system load forecast, for each month, and then averaging the monthly values across the year.[193]

PG&E's approach to battery storage resources forms the core of CalCCA's concerns regarding PG&E's original RA SoD proposal. Because PG&E represents charging as a negative quantity and discharging as a positive, taking the average of all hours results in *a* near-zero RA quantity for storage.[194] That result is not reasonable, fails to comport with market realities, and produces nonsensical results in the PCIA.

3. PG&E's Original RA SoD Proposal Conflates Capacity and Energy and Ignores the Value Storage Provides.

PG&E's proposed adjustment to offset every hour of storage discharge RA with the hours required to charge battery storage conflates capacity and energy concepts and improperly values the RA capacity in the PCIA.[195] PG&E explains in its direct testimony that storage resources can be counted as RA during any hour provided that the LSE can demonstrate that its portfolio contains sufficient excess charging capacity to support that level of discharge.[196] Because battery storage is not perfectly efficient, more energy is required to charge the battery than can be discharged over a period of time.[197] Despite this inefficiency, battery storage has value in addressing one of the key issues facing California as it seeks to meet its clean energy goals: it can move capacity from a period of excess capacity (typically when solar resources are generating) to a different period when

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[192] *Id*.
[193] *Id*. at 5-11.
[194] *Id*. at 4-12, and 5-11 to 5-12.
[195] Exh. CalCCA-01C at 13.
[196] Exh. PGE-01E at 4-12.
[197] Exh. CalCCA-01C at 14.

the capacity is needed (typically when solar resources have stopped generating).[198] The value proposition for battery storage resources should reflect this ability to provide capacity in any hour (when it is charged and available), in addition to the net energy value from charging and discharging.[199]

In the PCIA context, to the extent PG&E has energy settlement rights, the cost of energy to charge the battery and the revenue earned from energy discharge are already included as net revenue that is credited against the contract payments.[200] The value of RA retained by PG&E and used to count toward its bundled customer compliance obligation must also be recognized. PG&E's original RA SoD proposal fails to do this because it only captures the capacity value of the resources charging the battery storage but fails to capture the value of the storage itself.[201]

PG&E's original proposal to offset the RA capacity provided by battery storage with the hours required to charge the battery resources unfairly and inaccurately discounts the value of storage despite PG&E having capacity available to charge the storage resources.[202] PG&E has ██████ capacity available ██████████████████ ██████[203] Confidential Attachment B to the direct testimony of CalCCA witness Dickman includes a chart for each month comparing the quantity of resources available to provide RA with PG&E's hourly RA requirement, including the impact of charging and discharging battery storage.[204] Figures 8 and 9 below show two of those months, ██████████

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198 *Id*.

199 PG&E recognizes value streams for energy and capacity separately in its quantitative evaluation of new storage resources, as shown in Appendix E to AL 7602-E. *See* Exh. CalCCA-01C at 15, fn. 31.

200 Exh. CalCCA-01C at 15 (referencing Attachment C, PG&E response to CalCCA data request 2.03).

201 *Id*. at 15.

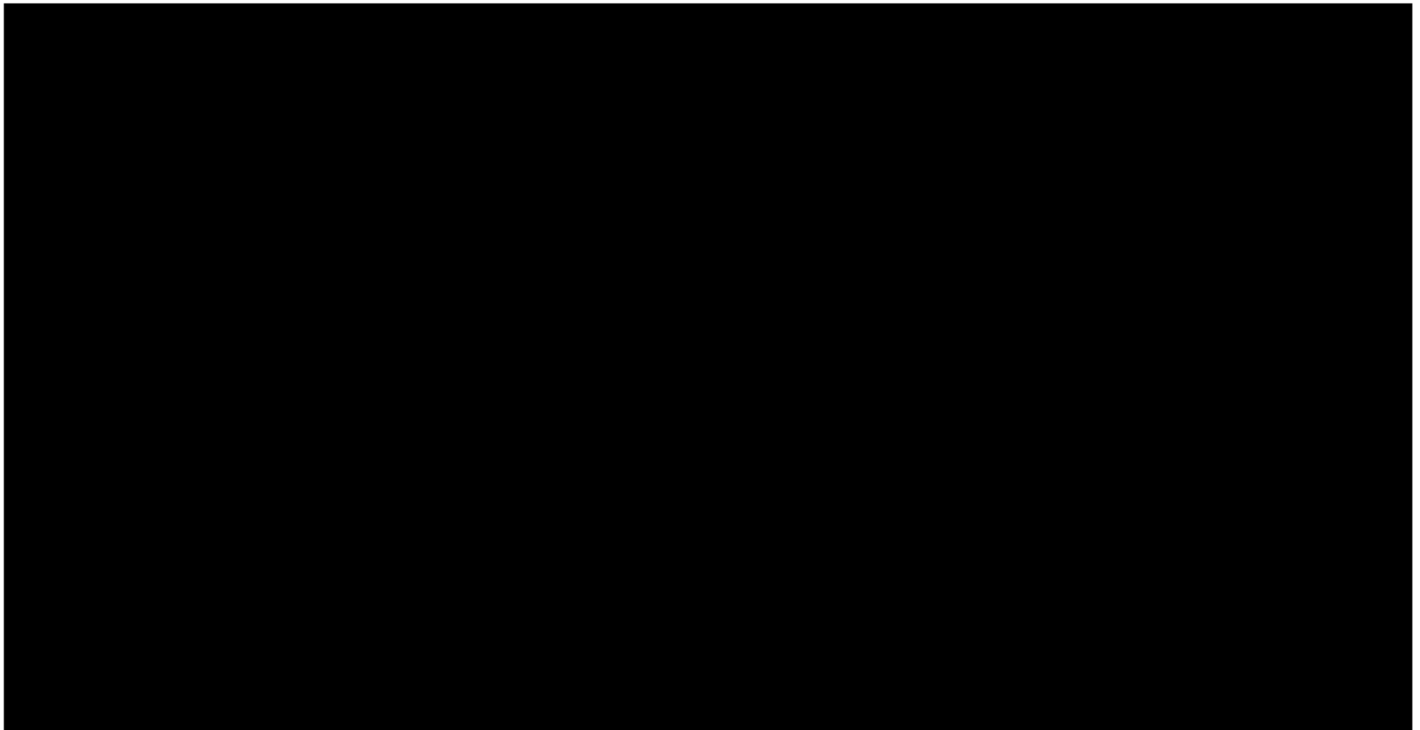
202 *Id*. at 16.

203 *Id*.

204 *See id*. at Attachment B.

As PG&E describes in testimony, storage resources are optimized to minimize the SoD RA open position across all hours. In the figures below, any shaded area above the dashed "RA Requirement" line, before and after accounting for storage resources, constitutes resources in excess of PG&E's SoD RA requirements.[205]

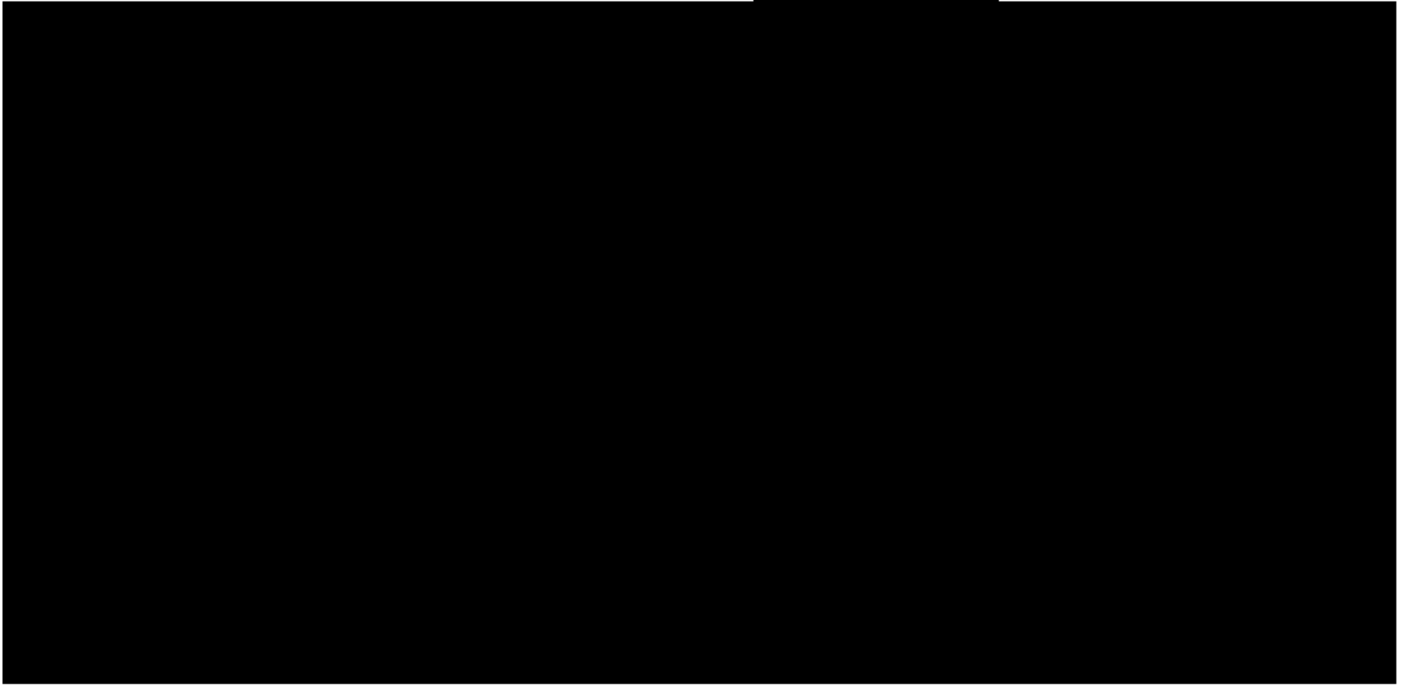
Figure 8: PG&E RA Position



[205] *Id*. at 16.

[206] Exh. CalCCA-01C at 17.

Figure 9: PG&E RA Position



These Figures amply demonstrate PG&E's , which allows it to Indeed, even in [208] By conflating energy and capacity, PG&E's original RA SoD proposal fails to recognize batteries' ability to provide capacity in any hour—a key capacity value proposition that exists separate and apart from batteries' net energy value from charging and discharging.

4. PG&E's Original RA SoD Proposal Pretends Battery Storage Has Little to No Cost in the Market and Provides Little to No Benefit to Bundled Customers.

PG&E's original RA SoD proposal appears to be premised on the idea that the Commission's SoD framework requires a showing that LSEs have sufficient capacity available to

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207 Exh. CalCCA-01C at 17.
208 *Id.*

charge the battery storage before it can be counted as providing RA.[209] PG&E translates that requirement into its proposal to fully offset the RA capacity batteries provided by the capacity required to charge the batteries.[210] When applied to the PCIA framework, PG&E's original proposal results in little to no value from battery storage recognized in the PCIA even though PG&E plans to use the storage capacity as Retained RA for bundled customers.[211] This proposal misconstrues the RA value proposition and does not reflect PG&E's own interpretation of RA value.

The question of how to determine the value of RA capacity the IOUs retain for their own use was addressed by the Commission in D.18-10-019. The cornerstone of that approach is to value an attribute at the price at which it can be bought and sold.[212] In its 2025 ERRA Forecast testimony, PG&E further explained that the concept of Retained RA is equivalent to bundled customers purchasing RA products from PCIA resources:

> PG&E uses some of the RA in its PCIA-eligible portfolio to meet bundled service customers' RA compliance obligations. When PG&E uses or "retains" this RA for compliance, bundled service customers effectively "purchase" the RA from its PCIA-eligible portfolio at the applicable RA MPB. This "purchase" occurs not via a contract but wholly within rates via (1) a cost to bundled service customers in their generation rate and (2) an equal credit to or reduction in the PCIA rate. Because both departed load and bundled service customers pay the PCIA, part of the credit from retaining or "purchasing" RA products for bundled service customers' compliance goes to departing load customers and part of the credit goes back to bundled service customers. Since PG&E bundled service customers are currently a minority of customers in its service area, those customers are purchasing a significant portion, 48 percent in 2023, of the RA retained for their

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[209] *Id*. at 18.
[210] *Id*.
[211] *Id*.
[212] *See* D.18-10-019 at 73.

> compliance from departed load customers at the applicable RA MPBs.[213]

Applying this PG&E analogy—that using a PCIA-eligible resource to meet a bundled customer compliance requirement is the same as purchasing that attribute in the market at the MPB—to the instant question demonstrates the inadequacy of PG&E's original proposal.[214] If PG&E were to procure RA from battery storage in the market it would be required to pay the market price for the storage RA regardless of whether it had capacity available to charge the battery.[215] In fact, if PG&E does not already have excess charging capacity available, under the SoD framework, PG&E must procure both the battery storage resource *and* the capacity to charge the battery.[216] The same should hold true for RA retained from PCIA-eligible resources. Bundled customers should be required to pay for the battery storage RA they need for compliance as well as the capacity required to charge the battery. Contrary to that reality, PG&E's original RA SoD proposal charges bundled customers for the price of the battery storage RA, but treats the cost of charging capacity as an offset to that price.[217] PG&E's original proposal essentially takes RA from PCIA-eligible battery storage resources at zero or no cost from the PCIA portfolio.[218] In other words, the utility's proposal pretends battery storage capacity can be purchased at almost no cost in the market and, therefore, PG&E owes unbundled customers—who paid for those resources—nothing for the resources used for bundled customer compliance.[219]

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213 *See* Exh. CalCCA-01C at 18-19 (referencing A.24-05-009, PG&E Prepared Testimony, at 2-10, lines 6-20).

214 *Id*. at 19.

215 *Id*.

216 *Id*.

217 *Id*.

218 *Id*.

219 *Id*.

PG&E's original RA SoD proposal further implies that the seller of the storage RA would be willing to discount the price to zero dollars because the buyer must also procure charging capacity elsewhere.[220] No seller would agree to those terms, as PG&E's own transaction data demonstrates.[221] In discovery, PG&E provided a list of RA-only sales contracts it has executed [redacted] for delivery during 2025.[222] PG&E summarized the transactions based on the type of resource providing the RA and the prices realized for each. As shown in Table 2 in CalCCA witness Dickman's testimony,[223] the average price paid for RA from baseload resources with a flat NQC profile was [redacted]. Over a similar period, the average price paid for RA from standalone storage resources was [redacted]. When selling RA to other LSEs in the market, PG&E clearly did not give buyers a [redacted]. Yet, it proposes to do so when calculating the PCIA for storage it effectively purchases from unbundled customers.[224] This demonstrates that PG&E's proposal is out of alignment with the value of RA attributes bought and sold in the market, which is a fundamental flaw in the proposal.[225]

5. PG&E's Original RA SoD Proposal Produces Nonsensical Results in the PCIA.

A storage-adjusted RA position is needed to forecast residual capacity purchases and sales, as well as the hourly RA capacity needed to meet bundled customer compliance requirements.[226] However, PG&E's proposed aggregation of the hourly RA position for the PCIA produces a nonsensical result for battery storage resources. Specifically, by summing up an hourly RA profile

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220 *Id*.
221 *Id*.
222 *See id*. at Attachment C (PG&E supplemental response to CalCCA data request 1.48).
223 *Id*. at 20.
224 *Id*.
225 *Id*.
226 *Id*. at 22.

that includes offsetting charging (reflected as a negative) and discharging (reflected as a positive) energy from battery storage resources, PG&E's original RA SoD proposal effectively eliminates the MW capacity from battery storage that would receive a value credit in the PCIA.[227] Multiplying PG&E's proposed near-zero battery storage capacity by the RA Adder results in a *de minimis* value for Retained RA from battery storage being included in the Indifference Amount.[228]

Table 3 in CalCCA witness Dickman's testimony lists each battery storage resource included in PG&E's PCIA-eligible resource portfolio, which is projected to provide Retained RA for bundled customers.[229] As shown in that table, PG&E's 2026 Indifference Amount forecast includes 32 of these battery storage resources with a total NQC of 3,050 MW. However, under PG&E's aggregation proposal, these resources only count as providing [redacted] of Retained RA – just [redacted] of the resources' NQC –essentially [redacted].[230]

As described above, PG&E's current, Commission-approved method for determining the value of Retained RA provided by PCIA-eligible resources is to multiply the published RA Adder by the average annual quantity of PCIA-eligible RA used to meet bundled customer compliance needs.[231] Battery storage resources have historically been included in Retained RA using NQC because they are able to provide RA capacity during system peak hours.[232] Consistent with the current PCIA method, applying the RA Adder to the battery storage NQC would value the Retained RA at more than $574.3 million in 2026, or an effective price of $15.69/kW-month.[233] In stark

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[227] *Id*.
[228] *Id*.
[229] *Id*. at Attachment C (PG&E Response to CalCCA data request 1.41).
[230] *Id*. at 22.
[231] *Id*. at 23.
[232] *Id*.
[233] *See id*. at 23-24. This value is calculated using the 2025 Forecast RA Adders for Local and Flex RA, as included in PG&E's initial filing. The value will change when the 2026 Forecast RA Adder is updated in PG&E's October Update filing. id. at 24, footnote 42.

contrast, under PG&E's original RA SoD proposal, that same Retained RA would be valued at only , an effective price of just as shown in Table 4 in CalCCA witness Dickman's testimony[234]– or essentially .

In fact, if PG&E's annual average battery storage RA is shown on a monthly basis, it reveals that PG&E's proposal actually results in negative Retained RA attributed to battery storage in certain months.[235] Table 5 in CalCCA witness Dickman's testimony details PG&E's proposed monthly RA from battery storage and the proposed annual average, based on the data in Table 4 of the same testimony.

Negative Retained RA makes no sense in a PCIA context.[236] Applying a negative quantity to the RA MPB results in a negative RA value, meaning that under PG&E's proposal departed load customers would be required to pay for RA retained by PG&E to meet its bundled customer compliance requirements.[237] That is, CCA customers would end up paying not only for their own RA compliance obligations but those for bundled customers.[238]

PG&E's proposal to impose an extra charge on departed load customers and keep the RA for bundled customers does not maintain indifference for bundled or unbundled customers. A customer who has departed PG&E's service is owed a credit for its share of the benefits that are provided by the resources for which the departed customer continues to pay. PG&E's original RA SoD proposal suggests that the benefit can be negative, essentially imposing an extra charge on departed customers. Doing so, while PG&E keeps the RA capacity to meet its own bundled customers' procurement obligations, is a clear violation of the Commission's indifference standard.

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234 *Id*. at 24.
235 *Id*. at 25.
236 *Id*.
237 *Id*. at 25-26.
238 *Id*. at 26.

6. PG&E's Revised RA SoD Proposal Is Not Reasonable Because It Produces Illogical Results, and, Like PG&E's Original Proposal, Fails to Reflect How PG&E Values Storage RA When Evaluating Procurement Opportunities for Its Bundled Customers

PG&E presents a revised RA SoD proposal in its rebuttal testimony. The revised proposal is substantially different from PG&E's original proposal, both in terms of the underlying valuation methodology and its outputs. At a high level, PG&E abandons its original proposal that assigned weights to all 24 hourly slices and instead assigns a 100% weight to the CAISO peak hour in each month.[239] The result is the total amount of Retained RA calculated for each month only reflects PG&E's SoD RA supply and RA requirement in that CAISO peak hour.[240] PG&E's revised methodology also abandons its proposal to offset battery charging and discharging, and no longer results in batteries being assigned a near-zero quantity for RA valuation purposes. While the value of battery storage increases relative to PG&E's original proposal, PG&E's revised proposal results in a sharp decrease in the quantity of Retained RA from solar resources.[241]

CalCCA made substantial efforts to evaluate PG&E's revised RA SoD proposal in the time afforded to it, but several factors challenged those efforts. First, CalCCA had no prior warning of PG&E's about-face until it filed its rebuttal testimony. Despite committing to produce public and confidential workpapers contemporaneously with service of its testimony,[242] PG&E did not produce workpapers supporting its rebuttal testimony (including its revised RA SoD proposal) until the afternoon of September 24, a full day after PG&E served its testimony. Two days later, on September 26, CalCCA served discovery on PG&E to try and evaluate the revised RA SoD proposal (among other issues). PG&E served responses to CalCCA's discovery requests one week

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239 Exh. PGE-4 at 3-5.
240 *Id*.
241 *Id*. at 3-12.
242 *See* Pacific Gas and Electric Company's Reply to Protests and Responses at 16 (June 30, 2025).

later, on October 3. Despite the clear and obvious impacts of its proposal on the PCIA, PG&E declined to prepare and produce an updated PCIA workpaper reflecting the implementation of PG&E's revised RA SoD proposal.[243] The evidentiary hearing began two business days later, on October 7, during which CalCCA cross examined PG&E witness Keller, who sponsored PG&E's revised RA SoD proposal. While PG&E's responses to CalCCA's discovery requests and CalCCA's cross examination of PG&E witness Keller allowed CalCCA to develop a basic understanding of PG&E's revised RA SoD proposal, expedited discovery and cross examination over a two-week period—without workpapers on the impacts of that proposal on departed customer rates—are a far cry from the sort of record development the Commission should require to consider a policy proposal as impactful as PG&E's RA valuation proposal. Again, PG&E's revised proposal would result in a [redacted] increase to the PCIA revenue requirement, relative to PG&E's current approach to RA valuation. These procedural shortcomings lead to a situation where the Commission is being asked to adopt a massively impactful proposal that no party has had an opportunity to fully vet.

In the little time CalCCA has had to analyze the proposal, two major flaws have become apparent. First, like PG&E's original RA SoD proposal, PG&E's revised RA SoD proposal determines the quantity of RA provided by battery storage based on PG&E's optimized battery resource charging and discharging profile, which in turn is based on PG&E's RA requirements and supply.[244] That means, if PG&E's revised methodology were applied to a different LSE, it would lead to a different quantity of RA assumed to be provided by battery storage resources. It also means that if PG&E's revised methodology were applied to the same battery fleet on two

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243 Exh. CalCCA-12.

244 Exh. PGE-4 at

separate occasions, the methodology could produce vastly different results with respect to the Retained RA quantity, and therefore value, for that fleet.

PG&E confirmed certain of these mechanics in response to a CalCCA discovery request: "PG&E confirms that, if applied to each IOU, PG&E's methodology for retained storage would be consistent although the retained RA quantity for battery storage resources would likely be different for each IOU because the quantity retained would be a function of the optimized battery storage capacity used, which would be impacted based on each IOU's SoD RA requirements as well as their mix of SoD RA supply resources."[245] PG&E witness Keller further explained the impacts of PG&E's revised methodology during the evidentiary hearing:

> Q:[CalCCA Counsel] So, here you acknowledge that if PG&E's revised proposal were applied to each IOU, then the retained RA quantity for battery storage resources would likely be different for each IOU, because that quantity would be a function of the optimized battery storage capacity that is actually used, correct?
>
> A:[PG&E witness Keller] Yes.
>
> Q: And that capacity could be different for each IOU because it would depend on each IOU's Slice of Day RA requirements as well as their mix of Slice of Day RA supply resources, agreed?
>
> A: Yes.
>
> Q: So, in other words, if Southern California Edison Company modeled an optimized storage profile based on its own set of storage resources, and its own RA requirements, it might come up with a different storage profile, correct?

[245] Exh. CalCCA-9.

A: Yes.

Q: And then based on that profile, you would have to look at the storage being discharged in the CAISO peak hour each month to determine the storage being retained assuming PG&E's methodology were applied?

A: Yes.

Q: And that number that comes out of that exercise, that could be very different than PG&E's retained RA number for storage resources, correct?

A: Confirming when you say "different", we are meaning like the – the percent of the available capacity for a storage resource would be different between the two utilities.

Q: Thank you for that clarification. Yes, with that understanding, how would you answer.

A: Oh, sorry. Yes.[246]

The PCIA framework seeks to set the value of a capacity attribute in the California energy market as a whole: it does not differentiate based on location or which LSE purchases or uses the attribute. The same MW from the same generating facility has the same RA value within the PCIA framework regardless of which LSE operates it. Therefore, a methodology that produces a different Retained RA capacity (and therefore, a different RA value) for each LSE makes little sense in the context of the PCIA. The purpose of calculating Retained RA quantity is to determine the value of PG&E's PCIA resources, including its battery resources. The manner in which a specific LSE operates its batteries—including when those batteries are charged and discharged—should have no impact on the capacity value of those batteries to buyers and sellers in the market. Put differently, no seller in the market would discount a battery resource to reflect the manner in which

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[246] Evidentiary Hearing Tr. Vol. 1 at 70-71.

the buyer plans on dispatching the resource. PG&E's revised RA SoD methodology therefore produces an illogical result.

PG&E's revised RA SoD methodology also fails to reflect the manner in which PG&E itself values storage RA when evaluating procurement opportunities for its bundled customers. In Advice Letter (AL) 7602-E, filed on May 21, 2025, for example, PG&E sought Commission approval of a power purchase agreement for long-term RA for an 80 MW, four-hour duration standalone battery storage facility (Pastoria).[247] PG&E undertook the procurement pursuant to the Mid-term Reliability (MTR) requirements of D.23-02-040.[248] PG&E indicates in its advice letter seeking approval for Pastoria that cost recovery will be net of any CAISO charges and market revenue, and net of any retained RA capacity value for bundled customers.[249] In other words, to determine cost recovery for Pastoria, the utility had to value the retained RA capacity from the battery.[250] That means, when evaluating the value of battery storage RA needed for bundled customers for Pastoria, PG&E used the resource's NQC and the capacity price.[251] PG&E did not apply a discount to the quantity of RA it must purchase, as it proposes to do for the storage it effectively purchases from unbundled customers through the PCIA.[252] In fact, PG&E's

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[247] *See* Exh. CalCCA-01C at Attachment C (PG&E response to CalCCA data request 3.01, Advice Letter 7602-E).

[248] *Id*. at 21.

[249] *See id*. at Attachment C (PG&E response to CalCCA data request 3.01, Advice Letter 7602-E at 9).

[250] PG&E defines that capacity value as follows: Capacity Value is applicable for all Agreement Types. It is the net present value of monthly capacity values across all months during the delivery period. The monthly Capacity value (C) is computed as the sum of two components: 1) the monthly Net Qualifying Capacity multiplied by the Local or System capacity price, and 2) the monthly Effective Flexible Capacity (EFC in MWs) provided by the project multiplied by the flexible RA price. These values are then discounted back by the discount factor for the month. *See id*. at Attachment C (PG&E response to CalCCA data request 3.01, Advice Letter 7602-E, Appendix E at E-3) (emphasis added).

[251] *Id*. at 21.

[252] *Id*. at 22.

quantitative evaluation of new procurement in AL 7602-E is consistent with its existing approach to calculating the RA value of its PCIA resources.[253]

In rebuttal testimony, PG&E sought to address this obvious conflict between how it proposes to value capacity in this proceeding and how it values that capacity in the market. The testimony denied that PG&E valued the RA associated with Pastoria based on its full NQC, and asserted its "initial valuations for Pastoria and similar projects from the [MTR] solicitation" applied a discount to the capacity such that the project's RA provided less RA value than comparable baseload SoD RA resources.[254]

Counsel for CalCCA asked PG&E's witness Keller several questions about the "discount" PG&E applied to Pastoria's RA capacity during the evidentiary hearing.

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253 *Id.*

254 Exh. PGE-4 at 3-3 to 3-4.

255 Confidential Tr. Vol. 1 at 65:2-4.

256 *Id.* at 65:18-22.

In contrast, PG&E's original RA SoD proposal would result in batteries receiving close to zero RA value, and PG&E's revised RA SoD proposal would result in batteries receiving only [259] of the value of comparable baseload SoD RA resources. Each result is a substantially greater discount than the discount PG&E applied to storage RA when evaluating procurement opportunities for its bundled customers. PG&E's internal practices, therefore, undermine its own RA SoD proposals.

Finally, during the evidentiary hearing, PG&E witness Keller indicated that PG&E would prefer if the Commission adopted its revised RA SoD proposal rather than its original RA SoD proposal.[260] Yet, witness Keller would not take the position that PG&E's revised proposal is superior to or more reasonable than PG&E's original RA SoD proposal:

> Q: [CalCCA Counsel] Mr. Keller, presumably, you would like the Commission to adopt the revised proposal over the direct proposal because you think that the revised proposal is superior to the direct proposal; isn't that fair to say?
>
> A: [Witness Keller] No. I would describe the revised proposal as being a compromise with CalCCA's preferred proposal.

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257 *Id*. at 65:23-66:4.
258 *Id*. at 66:22-67:5.
259 Exh. PGE-4 at 3-11.
260 Evidentiary Hearing Tr. Vol. 1 at 50.

> Q: Okay. But to be clear, you're not suggesting this is [a] settlement proposal; right? This is still PG&E's proposal?
>
> A: Yes. That is correct.[261]

Witness Keller's responses are concerning because they suggest PG&E's revised RA SoD proposal represents an attempt at compromise with CalCCA, rather than a principled methodology that produces a reasonable calculation of the value of RA associated with PG&E's PCIA resources. The Commission need not and should not accept that "split the difference" outcome in this case. It should take its time to carefully examine this complicated issue in the PCIA Rulemaking and arrive at a durable solution that comprehensively addresses the impacts of SoD on the PCIA framework.

7. The Commission Should Fully Evaluate the Implications of SoD on the PCIA Framework in the PCIA Rulemaking, So That Any Resulting Changes to the PCIA Framework Are Applied Consistently Across IOU Service Territories.

PG&E's RA valuation proposals are premature and made in the wrong proceeding. These proposals come at a time when the full impact of SoD on RA value, and how it should be reflected in the PCIA, is still unknown. The Commission and stakeholders spent considerable time and effort evaluating the SoD framework and preparing for implementation in 2025.[262] However, again, the Commission has not addressed how—or if—the SoD framework should impact the PCIA framework.[263] While the Commission has approved SoD implementation for RA compliance purposes, it has not provided direction regarding changes that may be required to incorporate RA

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261 *Id*. at 51.
262 Exh. CalCCA-01C at 26.
263 *Id*.

compliance changes into the PCIA template for all IOUs to ensure RA continues to be valued correctly and consistently under SoD.

For example, the RA Adder published in early October 2025 is calculated as the average $/kW price for RA from any resource technology and for the entire forecast year.[264] Consistent with D.25-06-049,[265] the RA Adder is based on transactions executed from December 2022 through August 2025 for delivery in 2026.[266] Because SoD compliance was not effective until 2025, it is not clear how the market prices for RA reflect the transition from the prior single-peak RA framework to the SoD model.[267] Energy Division will likely need to gather more transactional data than it currently collects to understand and quantify the impact of SoD in the market, including whether RA prices vary based on the underlying resource technologies.[268] However, that work has not yet begun, and it is unclear what, if any, changes are needed to ensure that the calculation of Retained RA accurately reflects the value these resources provide to bundled customers and, in turn, whether that calculation results in indifference for unbundled customers.[269]

Importantly, any changes to the calculation of Retained RA should be applied consistently across the three IOU service territories. Put differently: there is no good reason for the Commission to answer this question in three different ways. The easiest way to ensure consistency is to address the impacts of SoD on the PCIA framework in the PCIA Rulemaking. Addressing this issue in each utility's ERRA Forecast proceeding, in contrast, will lead to an unnecessary and unjustified patchwork of RA valuation approaches across the state.

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264 *Id*. at 27.
265 D.25-06-049.
266 California Public Utilities Commission, Market Price Benchmark Calculations 2025 (Oct. 1, 2025) (2025 MPB Calculation).
267 *See* Exh. CalCCA-01C at 27; 2025 MPB Calculation.
268 Exh. CalCCA-01C at 27.
269 *Id*.

Indeed, the three IOUs are not on the same page regarding how or when the impacts of SoD should be reflected in the PCIA framework. SCE argues that under the SoD framework, a resource's RA quantity should reflect the reliable capacity provided by the resource over a full 24-hour period.[270] Therefore, SCE proposes to represent RA as the "baseload equivalent" RA for each resource type based on how the resource contributes to SCE's hourly compliance requirements.[271] This baseload equivalent results in monthly RA quantities in the Indifference Amount that, for some resource types, are modified from NQC using an "SoD RA Effectiveness Factor."[272] The Commission adopted SCE's SoD proposal on an *interim* basis in that utility's 2025 ERRA Forecast case but stated, "[t]he issues of whether hourly RA MPB prices are needed and how to achieve proper accounting for storage and hybrid resources under SoD are both ripe for consideration in a rulemaking proceeding."[273]

San Diego Gas & Electric Company (SDG&E), in contrast, acknowledges in its ERRA Forecast testimony that SoD RA compliance has been adopted by the Commission but that no changes to the PCIA methodology have been approved.[274] SDG&E's testimony states:

> D.22-06-050 adopted a 24-hour slice of day ("SOD") approach to RA program requirements. At the time of this May filing, <u>no changes to the PCIA RA methodology for SOD have been approved by the Commission</u>. SDG&E is therefore making no such changes to the PCIA methodology for RA in this filing, and the methodology is consistent with prior years' filings.[275]

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270 *Id*. at 28.
271 *Id*.
272 *Id*.
273 D.24-12-039 at 75.
274 Exh. CalCCA-01C at 29.
275 *Id*. at 28 (referencing SDG&E Prepared Direct Testimony of Sheri Miller, A.25-05-012, at SM-5 lines 7-11 (emphasis added)).

The three IOUs' divergent views on the impact of SoD on the PCIA framework illustrate precisely why addressing this issue in individual ERRA Forecast proceedings will inevitably lead to inconsistent changes to the common PCIA framework, decreasing the transparency of the PCIA rate calculation and reducing the comparability of PCIA rates between IOUs.

The Commission should therefore take up this issue in Track 2 of the PCIA Rulemaking and evaluate the impact of SoD RA compliance on the PCIA framework as applicable to SCE, PG&E, and SDG&E. The final answer to the question of what impacts SoD will have on the PCIA framework may be a combination of modifications to RA quantity *and price*, but the Commission, the three IOUs, and other interested parties, including CalCCA, should conduct further analysis in the PCIA Rulemaking Proceeding before reaching a conclusion. Indeed, the preliminary scope of Track 2 of the PCIA Rulemaking Proceeding specifically includes the following issue: "Consideration of the need for ERRA-specific implementation guidance for RA program changes, including those related to the implementation of the Slice of Day framework, as was raised in the 2025 ERRA forecast."[276] After completing that evaluation, each IOU should consistently implement the resulting Commission directives in their individual ERRA Forecast proceedings. In the meantime, the Commission should direct PG&E to calculate Retained RA in its 2026 ERRA Forecast the same way it has in past ERRA Forecast cases.

8. If The Commission Adopts an Interim RA Valuation Method to Account for the Implementation of SoD, It Should Adopt the Interim Method Approved For SCE.

SCE first proposed its interim approach to reflect the SoD framework in the PCIA template in Supplemental Testimony filed in its 2025 ERRA Forecast (SCE Interim SoD Method).[277] SCE

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[276] *See* PCIA OIR at 24.
[277] Exh. CalCCA-01C at 30.

revised its proposal in response to issues raised by CalCCA in that proceeding, and in D.24-12-039, the Commission approved SCE's proposal "for the purposes of the 2025 ERRA forecast."[278] SCE also applied its updated interim SoD proposal in its 2026 ERRA Forecast.[279]

According to the SCE Interim SoD Method, baseload resources that deliver consistent output throughout the day continue to count up to their NQC for the month.[280] For intermittent resources (e.g., wind, solar), the RA quantity is the average of their hourly exceedance values, which vary depending on the region and technology.[281] Stand-alone battery storage resources are calculated as the storage NQC minus an estimate of the RA capacity needed for charging.[282] SCE's formula for calculating the RA quantity from storage resources is: NQC – NQC * 4 / 24 / Round Trip Efficiency.[283] In its 2026 ERRA Forecast testimony, SCE describes its treatment of energy storage as follows:

> In the SOD framework, storage resources are not assigned specific pre-determined hourly quantities for the hourly capacity determination. Instead, storage resources are optimized to address RA shortfalls during any hour of the day. Furthermore, the CPUC's QC methodology for energy storage has not changed. It is still based on the capacity (MW) level at which the storage resource is capable of discharging for four or more consecutive hours. Under the previous RA framework, storage resources with a duration of four hours or more are deemed equivalent to baseload for RA counting, underscoring their ability to provide capacity during the peak period. Therefore, their RA quantity can still be based on their NQC value. However, the SOD rules introduced an additional requirement: storage resources can only be counted towards RA if there is sufficient charging capacity. The combination of storage resources and the charging RA capacity provides a solution equivalent to baseload. Therefore, the effective contribution from storage is calculated as the storage NQC minus the RA capacity needed for charging.[284]

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[278] D.24-12-039 at 75.
[279] Exh. CalCCA-01C at 30 (referencing A.25-05-008, SCE-01 at 129:20 – 130:2).
[280] *Id*. at 30 (referencing A.25-05-008, SCE-01 at 131:19-22).
[281] *Id*. at 30 (referencing A.25-05-008, SCE-01 at 131:24-132:8).
[282] *Id*. at 30 (referencing A.25-05-008, SCE-01 at 132:10-22).
[283] *Id*. at 30 (referencing A.25-05-008, SCE-01 at 132:26).
[284] *Id*. at 30 (referencing A.25-05-008, SCE-01 at 132:10-21).

SCE's Interim SoD Method reflects that storage is not available in all 24 hours like a baseload resource but also reflects that storage is similar to baseload resources in that it can be used to provide RA in any hour as long as it can be charged.[285] In this way, and contrary to PG&E's approach, SCE's approach recognizes the capacity value storage has in shifting excess capacity from one part of the day to another part of the day when capacity is needed.[286] And under SCE's approach, in this way similar to PG&E's, the charging capacity provided by other resources is valued as Retained RA in the PCIA.[287]

Table 6 in CalCCA witness Dickman's testimony shows that applying SCE's interim method for energy storage to the PCIA-eligible storage resources in PG&E's case increases the RA value from [REDACTED] as originally proposed by PG&E to $458.2 million.[288] Applying SCE's method results in storage being valued at about 79 percent of baseload.[289] This aligns closely with the discount [REDACTED]

[REDACTED]

[REDACTED]. It contrasts sharply with PG&E's RA SoD proposals in this proceeding, which would value storage at approximately [REDACTED] (revised proposal) or near 0 percent (original proposal) of baseload.

SCE's Interim SoD Method is more reasonable than PG&E's revised RA SoD proposal not only because it produces a result that better comports with market realities, but also because, unlike PG&E's proposal, it would produce the same discount for battery storage RA (relative to baseload) if applied to any IOU. That is because SCE's Interim SoD method uses a formula that produces a

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285 *Id*. at 30.
286 *Id*.
287 *Id*.
288 *Id*. at 31.
289 *Id*. at 33.

fixed discount for a battery storage resource relative to its maximum capacity, rather than an LSE-specific optimized quantity that the battery would deliver in any given hour.[290] This result makes good sense in the context of the PCIA, where the objective is to determine the RA value of storage resources—that value should not vary based on the LSE's optimized dispatch of its battery resources.

While SCE's Interim SoD Method is more reasonable than PG&E's original and revised proposals, SCE's proposed framework is not flawless. SCE explains in testimony that it does not assume any changes to the MPB price used to value RA for SoD compared to the current single-hour RA compliance framework.[291] Therefore, SCE's proposal creates a 'Baseload Equivalent' RA quantity and applies that to the existing RA Adder.[292] Applying the RA Adder to a Baseload Equivalent quantity from different resource technologies implies that the RA Adder is also a baseload equivalent market price; however, to date, SCE has provided no analysis to support that assumption.[293] If different resources have different values under a SoD framework, and the RA Adder is the average price of all transactions for all resource types, the MPB, as currently calculated, must *not* be a baseload equivalent price.[294] The disjointed result is SCE's methodology seeks a baseload-equivalent value using a baseload-equivalent quantity, but a *non*-baseload equivalent price.[295]

Again, as discussed above, the implications of SoD on the PCIA framework may include a combination of modifications to RA quantity and price, but the Commission, the three IOUs, and

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[290] Exh. CalCCA-09.
[291] Exh. CalCCA-01C at 32.
[292] *Id*.
[293] *Id*.
[294] *Id*. at 33.
[295] *Id*.

other interested parties, including CalCCA, should conduct further analysis in the PCIA Rulemaking Proceeding before reaching a conclusion on this issue. Therefore, CalCCA recommends the Commission direct PG&E to maintain its existing approach to valuing its RA capacity until that analysis occurs; however, if the Commission adopts an interim change to PG&E's existing approach, it should adopt SCE's Interim SoD Method, and not PG&E's proposals.

C. USING A FINAL RA MPB DERIVED FROM THE METHODOLOGY ESTABLISHED IN D.25-06-049 PERPETUATES UNLAWFUL RETROACTIVE RATEMAKING (SCOPING ISSUE 1)

PG&E states that in its October Update, it will apply the new RA MPB calculation methodology adopted in D.25-06-049 to the 2025 Final RA MPB.[296] In that decision, the Commission found that the current methodology for calculating the RA MPB leads to outcomes inconsistent with Public Utilities Code Sections 365.2 and 366.2.[297] Accordingly, the Commission ordered revisions to the Forecast RA MPB that combined the system, local, and flex RA MPBs, utilized a three-year transaction window, and removed non-market-based and redundant transactions.[298] PG&E will apply this new Forecast 2026 RA MPB to the calculation of its 2026 forecasted indifference amount, which CalCCA supports.

However, the Commission should not require PG&E to true-up its Forecast 2025 RA MPB, derived from the *old calculation methodology,* using a Final 2025 RA MPB derived from the *new calculation methodology,* because doing so will perpetuate unlawful retroactive ratemaking. Decision 25-06-049 modified not only how the Forecast 2026 RA MPB should be calculated but also how to calculate the Final 2025 RA MPB true-up of the Forecast 2025 RA MPB rate, which

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[296] Exh. PG&E-1E at 12-11; Exh. PG&E-4 at 1-3.
[297] D.25-06-049 at 13-17.
[298] *Id*. at OP 1.

was set last year. Similar to the changes for the Forecast 2026 RA MPB, the Decision required Energy Division to calculate the Final 2025 RA MPB by combining the system, local, and flex RA MPBs; utilizing a four-year transaction window; and removing non-market-based and redundant transactions from the calculation of the RA MPB.[299] The order came despite the fact the Forecast 2025 RA MPB did not include these new components.

This retroactive change to how to set the 2025 PCIA revenue requirement impacts rates across a number of proceedings, including the PCIA rates set in this proceeding. As such, CalCCA filed its AFR of D.25-06-049 arguing that the decision establishes a new ratemaking scheme, instead of merely conducting a true-up, and, therefore, constitutes impermissible retroactive ratemaking.[300] Granting the relief requested in the AFR would result in the Commission only applying its new ratemaking formula on a forward looking basis to the calculation of the 2026 Forecast RA MPB, and not *retroactively* to the Final 2025 RA MPB. Therefore, declining to retroactively apply the new methodology would result in calculating the Final 2025 RA MPB according to the formula that existed prior to D.25-06-049, and preserving the "true-up" nature of determining the final value of PG&E's capacity portfolio in 2025.[301]

Unfortunately, the AFR remains outstanding,[302] Energy Division recently published a Final 2025 RA MPB that cannot lawfully be implemented here,[303] and PG&E recently filed its October

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[299] *Id*. at 20-21, COL 10, and OP 1.

[300] R.25-02-005, *California Community Choice Association Application for Rehearing of Decision 25-06-049*, pp. 13-35 (July 28, 2025) ("AFR").

[301] *See, e.g.*, *id*. at 4.

[302] CalCCA may deem the AFR denied as of September 26, 2025, but is not required to do so. Pub. Util. Code § 1733 (stating "absent further order of the commission, the order shall not stand so suspended for more than 60 days after the date of filing of the application, at which time the suspension shall lapse, the order shall become effective, application *may* be taken by the party making it to be denied.") (emphasis added).

[303] *See* California Public Utilities Commission, Energy Division, *Market Price Benchmark Calculation 2025* (Oct. 1, 2025) (2025 MPB Calculation).

Update. The Commission should grant the AFR expeditiously and order steps be taken in this case in time for PG&E to properly set 2026 rates.

1. CalCCA's AFR Should Be Granted Expeditiously to Avoid Setting 2026 PCIA Rates that Violate the Law.

Section 728 of the Public Utilities Code grants the Commission the authority to "fix, by order," the "just, reasonable, or sufficient rate, classifications, rules, practices, or contracts to be *thereafter* observed and in force."[304] The California Supreme Court directs that section 728 limits the Commission's jurisdiction by prohibiting ratemaking being applied retroactively.[305] In *Southern Cal. Edison Co. v. Pub. Util. Comm'n,* (1978) 20 Cal.3d 813, the Court observed that "before there can be retroactive ratemaking there must at least be *ratemaking.*" The Court summarized the hallmarks of "general ratemaking" to be that: (1) the Commission considered "many variables" and formulated "broad policy" in its setting of the "general rates"; and (2) the Commission's action had a significant financial impact on customers and LSEs affected that would not have otherwise occurred.[306]

As discussed in CalCCA's AFR, in arriving at D.25-06-049*,* the Commission took many variables into account to formulate broad ratemaking policy, including the key question of determining the relative cost share of above-market generation costs between bundled and departed customers.[307] The Decision itself summarizes that "questions that predominate this track of the [rulemaking] are of *policy.*"[308] Further, the new RA MPB methodology will have an

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[304] Pub. Util. Code § 728 (emphasis added).

[305] *Pacific Tel. & Tel. Co. v. Pub. Utils. Comm'n,* 62 Cal.2d 634, 650-652 (1965); *Southern Cal. Edison Co. v. Pub. Util. Comm'n,* 20 Cal.3d 813, 817-818 (1978) (reaffirming *Pacific Tel. & Tel. Co.'s* conclusion that "*general rate making* is legislative in character and looks to the future") (emphasis added).

[306] *Edison,* 20 Cal.3d at 828-830.

[307] AFR at 19-22.

[308] D.25-06-049 at 10 (emphasis added).

enormous impact on CCAs and unbundled customers in PG&E's October Update.[309] The Commission continues to keep parties in the dark on what the Final RA MPBs would have been had they been calculated under the prior methodology.[310] However, applying the change between the Forecast 2025 RA MPB and the modified Final 2025 RA MPB to PG&E's expected Retained RA quantity during 2025 decreased the value of capacity in PG&E's service territory in 2025 by approximately $621 million.[311] This $621 million impact is a substantial part of the enormous increase in PCIA rates in PG&E's October Update, with rates for some vintages increasing over 800 percent. The Commission should grant CalCCA's AFR and refuse to apply its new "general rate" retroactively based on the statutory prohibition on retroactive ratemaking given: (1) the ratemaking conducted in R.25-02-005 and implemented in the instant proceeding fits squarely in the definition of "general ratemaking"; (2) the massive impact of this general ratemaking on customers and LSEs; and (3) ordering this proceeding to apply the "general rate" to the 2025 revenue requirement amounts to unlawful retroactive ratemaking.

a. The Ratemaking Conducted in R.25-02-005 and Implemented in the Instant Proceeding Constitutes General Ratemaking.

SDG&E, SCE, and PG&E's (collectively, the Joint IOUs) Response to the AFR utilizes an erroneous reading of *Edison* and an overly broad reading of *Cal. Mfrs. Ass'n v. Pub. Utils. Comm'n,* 24 Cal.3d 251 (1979), to criticize CalCCA's definition of "general ratemaking." To reach

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309 AFR at 22-24.

310 *See* 2025 MPB Calculation at 1-3.

311 CalCCA calculated the $621 million reduction in the market value of capacity by using the 2025 PABA forecast PG&E provided in Workpaper "Chapter 12. ERRA 2026 Forecast WP PGE 20250515 Ch12 BA CONF". The Forecasted 2025 System, Local, and Flex RA Benchmark ($/kW-Year) values were each replaced with the Final 2025 RA Benchmark of $11.21 per kW-Month ($134.52 per kW-Year) in the Chapter 12 workpaper, producing a difference in the Market Value of Capacity of approximately $621 million. This result will be updated in CalCCA's comments on the October Update.

their preferred conclusion, the Joint IOUs misconstrue the Court's narrow discussion of "general ratemaking" in *Cal. Mfrs. Ass'n*, and they ignore the continued use of *Edison's* description of "general ratemaking" in cases that followed *Cal. Mfrs. Ass'n*. The Joint IOUs also ignore the fact that CalCCA's approach to reforming the RA MPB closely follows the approach the Commission took in the cases underlying *Edison* and *Cal. Mfrs. Ass'n*. The Joint IOUs then put forward their own defective definition of "general ratemaking," but none of the Commission's ratesetting proceedings today would meet that definition—not even PG&E's Phase I GRC. The elements that define "general ratemaking" that CalCCA laid out in its briefing in R.25-02-005 still apply, and considering those elements under that definition, the Commission undertook "general ratemaking" in R.25-02-005 to develop the RA MPB methodology adopted in D.25-06-049.

1) Policymaking Remains the Hallmark of General Ratemaking.

Part of the Court's purpose in *Edison* was to synthesize prior precedent on the rule against retroactive ratemaking and provide the elements that differentiate between general rates and non-general rates, to clarify its application. It stated that "if the prohibition against retroactive ratemaking is to remain a useful principle of regulatory law," it "must be properly understood."[312] One sentence in *Cal. Mfrs. Ass'n* states that although *Edison* contains language that "'true' ratemaking procedures involve many variables and broad policy determinations, whereas fuel cost adjustment proceedings are 'narrowly restricted' and 'semi-automatic,'" such language "should not limit the commission to exercising its discretion and to determining policy only in general

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[312] *Edison*, 20 Cal.3d at 816.

proceedings."[313] The Joint IOUs leverage that dicta to conclude "CalCCA's contention that policymaking in rate-related proceedings is the crucial 'hallmark' of general ratemaking is incompatible with, and directly contradicted by, the Court's holding in [*Cal. Mfrs. Ass'n*]."[314] The Joint IOUs continue, "CalCCA cannot reconcile the California Supreme Court's essential descriptions of general rates with its own, novel definition."[315]

However, the Joint IOUs overinflate the impact of that sentence. This is demonstrated by both the Court's opinion in *Cal. Mfrs. Ass'n* itself and in cases that continued to discuss *Edison's* elements after the Court decided *Cal. Mfrs. Ass'n*.

First, within the *Cal. Mfrs. Ass'n* case itself, the discussion of "general ratemaking" did not determine the outcome of the case. In that case, ratepayers challenged a Commission decision that approved rate increases and revised rate design from how both had been set in a prior GRC.[316] The Commission had determined the rate changes were necessary to recover higher fuel costs and to promote conservation.[317] The Court overturned the Commission's rate changes based on *a lack of evidence* supporting the Commission's conclusion that the revised rates would increase conservation.[318] The ultimate decision did not turn on the question of retroactive ratemaking.

However, the Court addressed the question of retroactive ratemaking because the ratepayers bringing the suit had alleged that rate increases and rate design changes can only be made in a GRC and not in a utility "offset case"—an ERRA-like proceeding in which the

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313 R.25-02-005, *Joint Response of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E), and San Diego Gas & Electric Company (U 902-E) on the Applications for Rehearing of Decision 25-06-049*, p. 14 (Aug. 12, 2025) (citing *Cal. Mfrs. Ass'n v. Pub. Utils. Comm'n*, 24 Cal.3d 251, 257 (1979)) ("Joint IOUs' Response to AFR").
314 *Id*. at 15.
315 *Id*. at 11.
316 *Cal. Mfrs. Ass'n*, 24 Cal.3d at 256-257.
317 *Id*.
318 *Id.* at 259-260.

Commission adjusts utility rates due to "increases in fuel costs disproportionate to the variation in other costs."[319] It is in response to this question that the Court affirmed its determination in *Edison* that rates tracking changes in fuel costs are not "general rates" and, as a result, the Commission can revise such rates outside of a GRC.[320] The Court reasoned that prohibiting such changes would needlessly require the Commission to wait until the next GRC to make such changes.[321]

Moreover, at the time the sentence was written in 1978, the California IOUs were vertically integrated, the concept of CCA and electric service provider customers was not a part of the regulatory lexicon, and retroactive ratemaking was a shareholder versus ratepayer issue, not an LSE versus LSE, or ratepayer versus ratepayer issue, like it is in R.25-02-005. There largely were only two ratesetting proceedings the Commission managed: GRCs and fuel adjustments that took place via the advice letter process discussed in *Edison* or the offset proceedings discussed in *Cal. Mfrs. Ass'n*.[322] Indeed, it is likely the Court called the rates "general rates" in those cases because there simply were no other major ratemaking proceedings besides GRCs. In fact, *Cal. Mfrs. Ass'n* assumes that, if the Court was unable to address these "extraordinary changes in fuel costs and method of apportionment of the increase" in the offset proceeding, the only other option was a full GRC with its full "recalculat[ion of] all expenses, revenues, rate base, and rate of return."[323] Needless to say, that is no longer how the Commission operates.

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319 *Id.* at 254-255.

320 *Id.* at 257.

321 *Id*. at 258.

322 The Commission confirmed as much in Decision 86974 (SCE's 1976 general rate case), when it discussed how very few matters were pending when it had issued Decision 85294 (a partial general rate increase granted on December 30, 1975). At the end of 1975, the Commission had before it only "three matters affecting the overall rate design issue" for SCE, (*see* 1976 Cal. PUC LEXIS 59, *125-126), one of which was the fuel cost adjustment tariff decision that eventually got appealed in *Edison*.

323 *Cal. Mfrs. Ass'n*, 24 Cal.3d at 258.

Second, the cases following *Cal. Mfrs. Ass'n* also demonstrate the limited impact of the language on which the Joint IOUs rely. In particular, in *Ponderosa Telephone Company v. Public Utilities Commission*, decided by the California Court of Appeals in 2011, the court found prohibited retroactive ratemaking had occurred when the Commission retroactively revised a ratesetting formula—a change in methodology—for gains on sale of stock from a telephone company.[324] The court determined the Commission's revision of the formula "retroactively revises costs that formed the basis for prior general rates," concluding that "[t]his is precisely the type of action prohibited by the retroactive ratemaking doctrine."[325] In doing so, the court discussed the elements of general ratemaking espoused in *Edison* and then distinguished the rate in *Edison* from the rate in *Ponderosa*.[326] The Court's analysis of *Edison*'s retroactivity standard made no mention that *Cal. Mfrs. Ass'n* somehow overruled *Edison* or otherwise limited or superseded *Edison*'*s* discussion of when "generating ratemaking" occurs.

Beyond *Ponderosa*, a line of Commission decisions after *Cal. Mfrs. Ass'n* was decided utilizing *Edison's* elements of "general ratemaking" in discussing the difference between general and non-general rates.[327] Thus, contrary to the Joint IOUs' argument, *Edison's* explanation of the

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[324] *Ponderosa Tel. Co. v. Pub. Utils. Comm'n*, 197 Cal. App. 4th 48, 63-64 (2011).
[325] *Id.* at 64-65.
[326] *Id.* at 63-64.
[327] *See, e.g.*, D.04-03-041, 2004 Cal. PUC LEXIS 80, at *12-17 (Mar. 17, 2004) (discussing *Edison's* elements of general ratemaking and concluding that the revised balancing account procedures in question did not adjust general rates based on hindsight review of a utility's earnings, was not part of a general ratemaking proceeding, and had no effect on general rates); D.07-12-056, 2007 Cal. PUC LEXIS 597, at *40-41 (using the *Edison* factors when considering a surcharge and determining that, under the *Edison*, it was not a general rate); D.10-10-036, 2010 Cal. PUC LEXIS 417, at *23; D.10-06-029, 2005 Cal. PUC LEXIS 576, at *67) (two of the Commission decisions that led to *Ponderosa*, these cases consider the *Edison* factors while determining the disposition of asset sale proceeds, refunds, and credits relating to a stock redemption).

difference between general and non-general ratemaking has remained in effect in both California courts and at the Commission well after *Cal. Mfrs. Ass'n* was decided.

2) No Current Commission Ratesetting Proceeding Would Meet the Joint IOUs' Definition of "General Ratemaking"

To combat the elements of "general ratemaking" CalCCA identified in *Edison*, the Joint IOUs' Response to the AFR puts forward its own narrow definition. That definition requires a general rate to:

(1) Establish "rate base, capital structure, rate of return and many other factors,"[328] including "a utility's return on investment, or profit;"[329] and

(2) Stay "fixed" until the utility's GRC "regardless of actual utility operating costs during the GRC period."[330]

This definition of "general rates" is quite narrow and fails to reflect the fact the Commission has spliced general ratesetting across tens of ratemaking proceedings that modify revenue requirements, cost allocation and/or rate design, including the PCIA rulemakings.

The Joint IOUs' definition is so narrow that no proceeding—including a Phase I GRC—would meet it. PG&E's Phase I GRC now only determines whether an IOU's proposed revenue requirements, costs, and recovery mechanisms for a specific test year are just and reasonable and should be reflected in rates.[331] That case does not determine any other part of the Joint IOUs' proposed definition of "general ratemaking," including the utility's capital structure, rate of return, return on investment, profit, updates to marginal costs, cost allocation, or rate design (the latter

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328 Joint IOUs' Response to AFR at 6.
329 *Id*. at 10.
330 *Id*. at 6.
331 *See, e.g.,* A.25-05-009, *Assigned Commissioner's Scoping Memo and Ruling* at 4-8 (Jul. 31, 2025).

three potentially being some of the "many other factors" CalCCA presumes the Joint IOUs mean to include in their definition). It is PG&E's cost of capital case that determines the capital structure, return on investment, and profit for the utility for a particular test year.[332] It is PG&E's Phase II GRC that determines marginal costs, cost allocation and rate design.[333] PG&E's Risk Assessment Mitigation Phase (RAMP) proceeding occurs prior to a GRC in order to examine the utility's assessment of its key risks and its proposed programs for mitigating those risks.[334] And many other costs today are authorized for cost recovery, allocated among different ratepayer groups, and included in rates in numerous other proceedings.[335]

As a result, rates established in a Phase I GRC no longer stay fixed, and are adjusted for far more than just operating costs to reflect decisions in these proceedings and many others. Those changes are then reflected in implementation proceedings such as the ERRA Forecast cases, Commission-ordered advice letters submitted after a proceeding closes, and/or each IOU's end-of-year consolidated rate change advice letters.[336] Far from staying "fixed", rates that are set in a Phase I GRC are constantly evolving and do not meet the definition of "general ratemaking" the Joint IOUs put forward.

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[332] *See, e.g.,* A.25-03-010, A.25-03-011, A.25-03-12, A.25-03-013 (not consolidated), *Assigned Commissioner's Ruling Consolidating Four Applications and Scoping Memo and Ruling*, p. 3 (July 16, 2025) (addressing the applications of all three IOUs related to "the cost of capital for test year 2026 for cost of equity, cost of preferred stock, cost of debt, and authorized capital structure.").

[333] *See, e.g.,* A.24-09-014, *Assigned Commissioner's Scoping Memo and Ruling* at 2-3 (Mar. 21, 2025).

[334] A.24-05-008, Assigned Commissioner's Scoping Memo and Ruling at 2-3 (Aug. 8, 2024).

[335] *See, e.g.,* D.21-06-035 at 97 ("To the extent that any resources procured in response to this order are subject to allocation using the power charge indifference adjustment (PCIA), the date of that adjustment shall be vintaged by the date of this order").

[336] *See, e.g.,* PG&E Advice Letter 7469-E (Dec. 30, 2024) ("The purpose of this 2025 AET advice letter is to provide a comprehensive update of the revenue requirements and rate changes since PG&E's Preliminary AET.").

Identifying whether rates are general or non-general requires the Commission to do more than just ask whether the rate was set in a GRC; it must follow the substantive analysis the Court used in *Edison*. When doing so, it becomes obvious that the PCIA rulemakings accomplish the same policymaking tasks for the PCIA as the GRC and its cousin proceedings establish for other rates. The creation of the current PCIA framework was the result of several major Commission decisions and a multi-year rulemaking process.[337] The Commission designated those past PCIA rulemakings (and its present rulemaking amending those rulemakings) as the avenue for determining: (1) which costs the PCIA recovers; (2) how to allocate those costs among customers; and (3) how to design rates to effectuate cost recovery.[338] PCIA rates constitute a significant portion of each IOU's generation rate, is billed to nearly every customer in the IOUs' service territories and appears alongside "Generation," "Transmission," and "Distribution" as a separate line item on those bills.[339] The most recent iteration of the PCIA rulemakings, R.25-02-005, clearly sets general rates.

3) ***Edison* Supports the Application of New Ratemaking Methodologies on a Going-Forward Basis Only.**

Another key flaw in the reasoning used in the Joint IOUs' Response to the AFR is the suggestion that the Commission in *Edison* did the same thing the Commission did in D.25-06-049, *i.e.*, overhauling an existing rate mechanism and applying that overhauled mechanism

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337 *See, e.g.,* D.18-10-019 and D.21-05-030.

338 *See*, *e.g.*, R.17-07-026; *see also* D.06-07-030; D.18-10-019; *and* D.21-05-030.

339 D.20-03-019 at 21.

retroactively.[340] The Commission appears to make this same mistake in its reasoning in D.25-06-049 when it disparages CalCCA's reliance on *Edison* as "curiously" chosen.[341]

However, both the Commission and the IOUs get *Edison* wrong on this key point and miss the obvious parallel between CalCCA's arguments in R.25-02-005 and what occurred in the investigation leading up to D.85871, the decision underlying *Edison*. There, the Commission used an investigation to revise a Fuel Clause Adjustment (FCA) for all three IOUs and establish a new Energy Cost Adjustment Clause (ECAC).[342] However, contrary to the Joint IOUs' assertion that the Commission was "applying the revised mechanism [*i.e.*, the ECAC] retroactively" in D.85871,[343] the Commission ordered a reduction in prospective rates that was to be calculated *using the existing FCA methodology*.[344] The Commission did *not* apply the ECAC retroactively to determine the amount of the going-forward rate reduction. In fact, the ECAC was a different mechanism not only in name, but also in how it operated and the costs it collected, so it could not have been applied retroactively.[345]

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340 Joint IOUs' Response to AFR at 9, 15-16 (stating "The Court summarized the Commission's actions in modifying the fuel adjustment clause to be based on actual costs, establishing a balancing account for fuel costs going forward, *then applying the revised mechanism retroactively* and ordering an amortized refund of the overcollections to customers. *Id*. at 822-824.") (emphasis added).

341 D.25-06-049 at 28.

342 *Edison*, 20 Cal.3d at 821-823.

343 Joint IOUs' Response to AFR at 9.

344 1976 Cal. PUC LEXIS 1480 (D.85731) at *23-24 (Apr. 27, 1976) ("We shall compute the specific amount of over- and undercollection for each of the respondents *under their respective existing fuel clauses* as of the latest date available and amortize that amount, adjusted as appropriate, initially over a period not to exceed 36 months and order a commensurate reduction in rates, subject to revision.") (emphasis added).

345 *Edison*, 20 Cal.3d at 822-824 (stating "While sharing many of the concerns voiced by critics of the clause, the commission determined that the cost adjustment concept should be preserved but the clause should be modified to eliminate the defects revealed by experience. The principal such defect, as we have seen, was the provision authorizing Edison to base its calculations on a prediction of its fossil fuel needs for the 12-month period following each application for a billing adjustment, premised on the assumption that 'average' weather conditions would prevail throughout that time. The commission abandoned this procedure, and in lieu thereof adopted a clause which operates on a 'recorded data' basis, i.e., on the actual

SCE never challenged the ECAC: it only challenged the reduction in prospective rates calculated based on the then-current FCA methodology.[346] The Court in *Edison* ruled that this was not "general ratemaking" because such a process "serves no purpose when the only business at hand is the application of a mathematical formula to a figure definitively established by reference to the utilities' books."[347] Thus, *Edison* does *not* set precedent for the Commission to apply *new* ratemaking methodologies retroactively; if anything, it does the opposite.

CalCCA has maintained since the beginning of R.25-02-005 that the process followed by the Commission in *Edison* is the correct path for the Commission to follow in both R.25-02-005 and the instant proceeding. The Commission can true-up last year's forecasted RA MPB with a final MPB, but to do so it should have used the pre-D.25-06-049 RA MPB methodology to conduct that true-up. This process would fall in line with the Commission's decision in *Edison*, applying the FCA—and not the ECAC—to calculate the amount of a future change in rates. Doing so is a matter of arithmetic, plugging updated values into an existing formula. Further, the Commission can revise the RA MPB, like it modified the FCA to become the ECAC, but it should have only ordered that revised RA MPB methodology be applied going forward like it did in the investigation underlying *Edison*.

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fuel expenses incurred by the utility during the period preceding its application for a billing adjustment….. By this device the possibility of large over- or undercollections accumulating in the future is eliminated. And because the commission expanded the clause to include all sources of purchased energy – e.g., nuclear and geothermal, in addition to fossil fuels – it renamed the device the 'energy cost adjustment clause.'").

[346] *Edison*, 20 Cal.3d at 824 ("Seen thus in its full perspective, the transitional procedure adopted by the commission to deal with these overcollections is surely 'fair and reasonable.' It is not significantly different from the operation of the 'billing account' under the new energy clause, and *Edison expressly disavows any challenge to the latter device*.") (emphasis added).

[347] *Id.* at 829 (citing *City of Los Angeles v. Public Util. Comm'n*, 15 Cal.3d 680, 695 (1975)).

b. The Commission Has Required the IOUs to Apply the New RA MPB Retroactively in This Proceeding.

The Joint IOUs' Response to the AFR argues that the application of the new RA MPB in this proceeding is not retroactive, suggesting last year's PCIA rates, calculated under the prior RA MPB methodology, were not a "rate approved by the Commission under which an order has become final."[348] And, even if they were, the Joint IOUs argue, the "financial impact the courts look to is that of the utility."[349] The first argument fails, considering: (a) the many times California Courts have determined that adjusting future rates to recoup past undercollections is retroactive in effect; and (b) the fact D.25-06-049 ordered the IOUs to do far more than merely true-up forecasted values with recorded values. The second argument is not only stuck fifty years in the past, it simply ignores the financial impacts on *ratepayers* the courts have looked to when applying the doctrine, and it reads limitations into the law where none exist.

1) A True-Up is Retroactive in Nature.

In the landmark retroactive ratemaking cases relied upon by both CalCCA and the Joint IOUs, the Court consistently has determined that adjusting future rates to account for past undercollections is retroactive in effect. In *Pacific Tel. & Tel.*, the Commission conducted an extensive investigation of the rates charged by the utility in question, found them to be unreasonably high, and fixed new, lower rates.[350] The Commission ordered the utility to refund to its customers all charges collected in excess of the new rate level since the beginning of the investigation.[351] The Court determined the new rate structure took effect "unlawfully

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348 Joint IOUs' Response to AFR at 18 (citing to *Edison*, 20 Cal.3d at 816).
349 *Id*. at 18.
350 *Pacific Tel. & Tel. Co.*, 62 Cal.2d at 641-642.
351 *Id.* at 649-653.

retrospectively."[352] Likewise, in *City of Los Angeles II*, the Court found that ordering a rate refund of the difference between rates found to be unreasonable and new, reasonable rates "would mean that the commission is establishing rates retroactively rather than prospectively."[353] In *Edison*, the Commission trued up three years of FCA overcollections, amortizing the recoupment of the value of those overcollections over the following three years of rates.[354] The Court acknowledged that while such an adjustment was not ratemaking, it was "retroactive in effect."[355]

Here, PG&E has already collected and recorded revenue to its PABA in 2025 based on PCIA rates approved by the Commission under a final order in D.24-12-038. Those rates were set based on a PCIA revenue requirement that was calculated, in part, by comparing the forecasted market value of PG&E's RA capacity portfolio during 2025 (a value determined in part by the RA MPB) to the cost of PG&E's RA capacity portfolio.[356] The PCIA framework requires PG&E to now modify its 2025 revenue requirement to reflect, among other things, a new methodology of calculating the RA MPB's proxy market values for capacity PG&E retained for its bundled customers in 2025.[357] Under *Edison*, *City of Los Angeles II*, and *Pacific Tel. & Tel.*, the modification of approved 2025 PCIA revenue requirements and rates based on recorded costs to date is retroactive in effect: it changes future rates (2026 PCIA rates) to account for past under- or

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[352] *See id.* at 652-653.

[353] *City of Los Angeles v. Public Utilities Commission,* 7 Cal. 3d. 331, 357 (1972) ("To permit the commission to redetermine whether the preexisting rates were unreasonable as of the date of its order and to establish new rates for the purpose of refunds would mean that the commission is establishing rates retroactively rather than prospectively.")).

[354] *Edison*, 20 Cal.3d at 815, 822.

[355] *Id.* at 830 ("Because the increased charges thus imposed were not the products of ratemaking, they were not rendered inviolable by the rule against *retroactive* ratemaking. To put it another way, the commission's decision to further adjust those rates so as to compensate for substantial past overcollections may well be retroactive in effect, but it is not retroactive *ratemaking*.") (emphasis in original).

[356] AFR at 5-10.

[357] Exh. CalCCA-01C at 4-10.

overcollections (calculated from 2025 PCIA rates). Stated another way, regardless of a change in the underlying ratemaking methodology, and whether such a change constituted "general ratemaking", the PCIA "true-up" and any modifications to it are retroactive in effect.

2) Decision 25-06-049 Applies a Wholesale Change to How Rates Should Have Been Calculated in Last Year's ERRA Forecast Case.

That retroactivity is exacerbated by the fact that D.25-06-049 ordered PG&E to do more than just "true-up" of the value of capacity in this proceeding; instead, it created *a retroactive change in how rates should have been calculated* in last year's PG&E ERRA Forecast case, A.24-05-009.[358] Stated another way, the Commission ordered a retroactive change to the rate formula itself and not just a retroactive update of the values used to populate that formula. The Commission did so *after* PG&E recovered the revenue requirement in rates set in 2025, reformulated how PG&E was to value its capacity portfolio in 2025 and, in turn, retroactively revised the Commission's definition of customer indifference in PG&E's service territory for 2025.

Such a change is more than a true-up because of the difference between market costs and market values, and the proxy nature of the RA MPB. In *Edison*, the Court emphasized both the mathematical nature of the FCA calculation refunds and the fact the future reduction in rates was calculated based on "empirical data" and figures "definitively established by reference to the utilities' books."[359] In other words, no complicated formula or methodology was needed to calculate what the actual costs of fuel were: they were what the IOUs paid, as entered in their accounting books.

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358 *Id*. at 28-31.
359 *Edison*, 20 Cal.3d at 828-829.

In this case, however, the Commission has ordered actuals be calculated for the more nebulous concept of the "portfolio value" of capacity, a concept that is not definitively set in, and cannot be solely derived from, the IOUs' accounting books. Instead, capacity portfolio value relies on the MPBs, administratively determined proxy used to assess the value of capacity within the IOUs' portfolios.[360] PG&E's October Update will not simply compare forecasted capacity value to actual capacity value when it applies the Final 2025 RA MPB in its October Update this year; it will be revising what constitutes the actual capacity value of its portfolio in 2025. Thus, unlike in *Edison*, PG&E's October Update will revise the "truth" of the value of retained capacity *itself* in 2025. No clear, easily verifiable actual market value of retained capacity exists to compare to the forecasted value.

Because portfolio market value is a subjective value, the shift in the revenue requirement that will come from using a revised RA MPB would not have occurred naturally, as a matter of course, over time. When truing up an apple with an orange, it is not possible for the orange to be the natural evolution of the apple. That is, unlike in *Edison*, a new RA MPB methodology cannot naturally leave CCAs and customers in the same place as the old RA MPB would have left them. Thus, the change ordered in D.25-06-049 goes beyond being a retroactive true-up; it applies a wholesale change to how rates should have been calculated in last year's ERRA forecast case.

3) Neither Section 728 Nor Legal Precedent Limit the Application of Retroactive Ratemaking to Only Utilities.

The Joint IOUs argue that in looking to the financial impacts of the prohibition against retroactive ratemaking, the Commission may only look to the impacts on the utility.[361] Of course,

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[360] D.19-10-001 at 6 ("Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the [PCIA] for a given year.").

[361] Joint IOUs' Response to AFR at 18.

that argument ignores how cases like *Edison* center on protecting *ratepayers* from utility windfalls.[362] While the IOUs are correct that *Edison*, *Cal. Mfrs. Ass'n* and *Ponderosa* look only to the financial impacts on a utility (and its ratepayers),[363] and not a CCA (or its ratepayers), the opposite is true as well: none of those cases limit the circumstances under which a claim of retroactive ratemaking can be made based on which customers or LSEs are impacted. That makes sense. Section 728 of the Public Utilities Code itself does not draw any lines limiting the impact of the doctrine. That section grants the Commission the authority to "fix, by order," the "just, reasonable, or sufficient rate, classifications, rules, practices, or contracts to be *thereafter* observed and in force,"[364] regardless of which LSEs or ratepayers those rates, rules or practices impact.

Here, the impacts on the Commission's retroactive ratemaking on CCAs and their customers are enormous, certainly meeting the "disruptive financial consequences of true retroactive ratemaking."[365] The Final 2025 RA MPB in PG&E's service territory is $11.21 compared to the Forecast 2025 RA MPB of $40.31 for System RA, $13.29 for Local RA, and $16.97 for Flexible RA.[366] As will soon be seen in PG&E's October Update, a decline in the RA MPB as significant as this decline will cause a significant increase to the PCIA revenue requirement and the rates CCA customers must pay. While Energy Division's on-going silence regarding what the RA MPBs would have been under a pre-D.25-06-049 methodology makes a full accounting impossible so far, it is clear the impact is large.

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[362] *See Edison,* 20 Cal.3d at 816-817, 824.

[363] Joint IOUs' Response to AFR at 18.

[364] Pub. Util. Code § 728 (emphasis added).

[365] *Edison,* 20 Cal.3d at 824-826.

[366] 2025 MPB Calculation at 1 (Energy Division's list of the RA MPBs from 2025 fails to update those MPBs for changes that occurred in a revised version of the MPBs on November 5, 2024).

2. Steps Should be Taken in this Proceeding to Ensure 2026 PCIA Rates Do Not Perpetuate Retroactive Ratemaking.

If the AFR is granted soon after this brief is filed, an Assigned Commissioner Ruling should be issued in this proceeding to require (1) Energy Division to recalculate the Final RA MPB using the correct formula; and (2) PG&E to recalculate the Portfolio Market Value, and the resulting PCIA rates, in a supplement to its October Update. If the AFR is granted well after PG&E's October Update, but prior to a final decision in this proceeding, the final decision should require: (1) Energy Division to recalculate the Final RA MPB using the correct formula; and (2) PG&E to recalculate the Portfolio Market Value, and the resulting PCIA rates, in its year-end consolidated rate change using the correct formula. If the AFR is not granted prior to a final decision in this proceeding, the final decision should include an ordering paragraph that enables either a subsequent phase, or next year's iteration, of this proceeding to address the necessary changes to PCIA rates on account of the resolution of the AFR. Taking one of these three actions, depending on the timing of the AFR's resolution, will avoid perpetuating the impermissible retroactive ratemaking ordered in D.25-06-049 and being carried out in this proceeding.

VI. UNCONTESTED ISSUES

In addition to the contested issues discussed at length above, CalCCA investigated a number of other issues raised by PG&E's Application. Below, this brief discusses two of those issues. CalCCA does not contest PG&E's position on these uncontested issues, but nevertheless discusses PG&E's responses to discovery requests on these issues for the Commission's awareness below. CalCCA reserves the right to address these issues in reply briefs or in comments on the October Update.

A. PG&E'S ASSUMPTION THAT NEW DATA CENTER LOAD WILL BE SERVED BY CCAS IS APPROPRIATE

This year, for the first time, PG&E is explicitly incorporating into its Sales and Peak Demand forecasts the impacts of new large data center load in its service territory.[367] While PG&E's testimony and supporting workpapers identify the data center energy and peak demand forecasts, they do not explain whether the new load will receive bundled service from PG&E, be served by a CCA, or take direct access from an energy service provider.

Based on PG&E's responses to discovery, CalCCA understands that generally, PG&E assumes that data centers located in CCA service territories will be served by the CCA. Specifically, PG&E assumes the new load will be served by the CCA after applying an opt-out rate of 13 percent, which it says is based on historical industrial customer opt-out rates.[368] PG&E included information about its data center forecast during the meet and confer process with CCAs,[369] and PG&E represents that it included new data center load in the individual CCAs' load forecasts in this case.[370]

CalCCA agrees it is correct to assume that new data center load located in CCA service territory will default to CCA service unless the customer opts out.[371] CalCCA has also advocated in other proceedings that CCAs be made aware of new large loads, including potential data center load, in their service territory in a timely manner.[372] CalCCA does not dispute PG&E's sales or peak demand forecasts, but reserves the right to address this issue in reply briefs, and/or contest this issue following its review of PG&E's October Update.

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367 Exh. PGE-01E at 2-11.

368 Exh. CalCCA-01C at 58 (referencing Attachment C, PG&E response to CalCCA data request 4.05).

369 *Id*. at 58 (referencing Attachment C, PG&E response to CalCCA data request 4.07).

370 *Id*. at 58 (referencing Attachment C, PG&E response to CalCCA data request 4.08).

371 *Id*. at 59.

372 *Id*.

B. PG&E SHOULD CORRECT ERRORS IN THE CALCULATION OF ITS ENERGY STORAGE RA FROM MODIFIED CAM RESOURCES

Several of PG&E's energy storage contracts were procured pursuant to D.19-11-016.[373] In that decision, the Commission directed that PG&E procure capacity on behalf of LSEs that elected not to self-provide capacity, and that the cost of such procurement be recovered from customers of those LSEs through a Modified CAM (ModCAM) surcharge.[374] The portion of ModCAM procurement undertaken for PG&E's bundled customers is recovered through the PCIA.[375]

In response to discovery requests issued by CalCCA, PG&E acknowledged that its PCIA workpapers erroneously included the CAM portion of Modified CAM resources rather than the PCIA share of the ModCAM resources, resulting in an understated amount of Retained RA included in the PCIA.[376] PG&E indicated in discovery,[377] and reaffirmed in rebuttal testimony,[378] that it will correct this error in its October Update to reflect the PCIA share of Retained RA from ModCAM resources. If PG&E's SoD proposal is adopted by the Commission, then PG&E should be required to correct the Retained RA from ModCAM storage resources. CalCCA will review PG&E's October Update to ensure PG&E corrects this error and reserves the right to address this issue in comments on the October Update following that review.

VII. CONCLUSION

For the foregoing reasons, CalCCA requests the Commission adopt the recommendations listed in CalCCA's Summary of Recommendations. CalCCA reserves the right to modify those recommendations based on updated information presented in PG&E's October Update, and to

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373 *Id*. at 34.
374 *Id*.
375 *Id*.
376 *Id*. at 34 (referencing Attachment C, PG&E responses to CalCCA data request 2.05 and 2.06).
377 *Id*. at 34 (referencing Attachment C, PG&E response to CalCCA data request 2.06).
378 Exh. PGE-04 at 3-13.

address other issues raised therein via comments on the October Update or any further process the Commission might adopt.

October 24, 2025

Respectfully submitted,

Nikhil Vijaykar
KEYES & FOX LLP
580 California Street, 12th Floor
San Francisco, CA 94104
Telephone: (408) 621-3256
E-mail: nvijaykar@keyesfox.com

Counsel for CALIFORNIA COMMUNITY CHOICE ASSOCIATION

October 14, 2025

VIA ELECTRONIC MAIL

Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Email: edtariffunit@cpuc.ca.gov

Re: California Community Choice Association's Comments on Draft Resolution E-5426 (Integrated Resource Plan Filing Citation Program)

Dear Energy Division,

Pursuant to Rule 14.5 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure,[1] and the cover letter accompanying Draft Resolution E-5426, California Community Choice Association[2] (CalCCA) submits these comments on Draft Resolution E-5426 (Integrated Resource Plan Filing Citation Program) (Draft Resolution), served September 24, 2025.

I. SUMMARY

The Draft Resolution replaces the citation program established by Resolution E-5080,[3] which authorizes Commission Staff to fine load-serving entities (LSE) for non-compliance with mandatory filing deadlines and reporting requirements for individual Integrated Resource Plans (IRP). The Draft Resolution authorizes Commission Staff to fine LSEs for non-compliance with *any* mandatory filing deadlines and reporting requirements in the planning and procurement

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1 *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021): https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf.

2 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

3 Resolution E-5080. *Approves a Citation Program Enforcing Compliance with the Filing Requirements of Integrated Resource Plans by Load-Serving Entities* (Aug. 7, 2020): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M344/K806/344806352.PDF.

tracks of the IRP proceedings. CalCCA does not oppose replacing Resolution E-5080 with the Draft Resolution, but modifications should be made to the Draft Resolution to ensure the rules and requirements of the citation program are clear and practical. In summary, the Commission should modify the Draft Resolution to:

- Ensure LSEs are not issued Citation Notices or citations for issues caused by circumstances outside their control;
- Provide at least *ten* (rather than five) calendar days to correct issues identified in Correction Notices and provide Energy Division Staff the authority to extend this time when necessary;
- Ensure LSE staff receive and respond to correction notices in a timely manner by emailing Correction Notices to the LSE's designated contact person for IRP filings, *or persons if more than one contact is provided*;
- Clarify that Scheduled Penalties for failure to comply with a reporting requirement are assessed per *filing,* rather than per instance; and
- Clarify that the amounts of the Scheduled Penalties set forth in the Appendix are not subject to appeal, *unless* the Respondent demonstrates the calculated citation amount is not consistent with the Specified Violations and Scheduled Penalties required in Table 1.

II. LSES SHOULD NOT BE SUBJECT TO PENALTIES UNDER THE DRAFT RESOLUTION FOR CIRCUMSTANCES OUTSIDE THEIR CONTROL

The Draft Resolution should be modified to clarify that LSEs will not be subject to penalties for circumstances outside their control. The Draft Resolution states:

> Commission Staff may use this citation program to issue citations and levy fines against LSEs for:
>
> - Failing to meet a deadline for filing an individual IRP, a compliance filing, or other document required to be filed in an IRP Proceeding; and
> - Failing to comply with a reporting requirement, such as the requirement to fully report all information included in the templates developed by Commission Staff as part of an individual IRP or compliance filing.[4]

In the past, last minute changes, template errors, and other technical issues have created challenges with completing filings on time and with the templates provided. Energy Division staff has, on occasion, issued revised templates just *days* before a filing is due. Other times, the

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[4] Draft Resolution, at 6.

instructions provided by the Commission have been ambiguous, contradictory, or otherwise unclear, unnecessarily shifting compliance risk to LSEs. In these cases, Energy Division staff has historically used its discretion to reasonably adjust filing requirements and deadlines on a case-by-case basis for these issues that arise outside of the LSEs' control. However, absent modification, the Draft Resolution would appear to remove this discretion.

The Draft Resolution should therefore be clarified to state that Correction Notices will only be issued for incomplete, incorrect, or missing information that fails to be resolved after conferring with Energy Division regarding the circumstances underlying the error or omission. When issues arise due to unclear filing instructions or last-minute updates, revisions, or additions to the templates (*e.g.,* modifications to a template made less than 30 days before a filing is due may or may not be enough time depending on the scope and breadth of the modifications), the Draft Resolution should allow Energy Division to provide LSEs with additional time to correct their filings before Correction Notices are issued.

III. THE DRAFT RESOLUTION SHOULD BE MODIFIED TO PROVIDE AT LEAST TEN CALENDAR DAYS TO CORRECT ISSUES IN CORRECTION NOTICES AND PROVIDE ENERGY DIVISION STAFF THE AUTHORITY TO EXTEND THIS TIMEFRAME

The Draft Resolution should be modified to provide at least ten, rather than just five, calendar days for LSEs to correct issues noted in Correction Notices. In addition, Energy Division Staff should be provided authority to extend this timeframe. Section 1.1 and 2.1 of Appendix A of the Draft Resolution state that a Correction Notice will provide an LSE "at least five calendar days for the LSE to correct the issue(s) identified." Section 2.1 of Appendix A similarly states that "(t)he Correction Notice will provide the LSE with at least five calendar days to correct the issue(s) identified."

The Commission should modify these sections to provide LSEs with at least *ten,* rather than just five, calendar days to correct any issues identified in a Correction Notice and give Energy Division Staff the ability to extend this period beyond ten days if it determines additional time is necessary. Resolution E-5080 provides LSEs at least ten calendar days to cure deficiencies.[5] Shortening this period to five calendar days is not practical. If Correction Notices are sent before a weekend or a holiday (*e.g.,* Thanksgiving Day), two calendar days could fall within this five-day window, providing very few business days for the LSE to respond. The Commission should therefore modify the Draft Resolution to provide at least *ten* calendar days to correct issues.

In addition, Resolution E-5080 provides Energy Division Staff the ability to extend the cure period if necessary.[6] The Draft Resolution appears to remove this ability. The Commission should modify the Draft Resolution to allow Energy Division Staff to extend the cure period

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[5] Resolution 5080, Appendix A, at 11.
[6] *Ibid.*

when necessary. IRP filing requirements and templates are often complex and time consuming to complete. An extended cure period may be necessary depending on the type of information requested by Energy Division staff.

IV. THE DRAFT RESOLUTION SHOULD BE MODIFIED TO ENSURE LSE STAFF RECEIVE AND RESPOND TO CORRECTION NOTICES IN A TIMELY MANNER

The Draft Resolution should be modified to ensure all specified LSE staff receive, and therefore are able to respond to, Correction Notices in a timely manner. Section 2.4 of Appendix A states that "Correction Notice(s) shall be sent by Commission Staff by electronic mail (e-mail) to the LSE's *designated contact person* for IRP filings." The Commission should modify this section to state that Correction Notice(s) shall be sent by Commission Staff by e-mail to the LSE's designated contact person for IRP filings, *or persons if more than one contact is provided*. Sending Correction Notices to *all* designated LSE contacts will help ensure that Correction Notices are received and responded to in a timely manner in the event of staff turnover or out-of-office schedules.

V. SCHEDULED PENALTIES FOR FAILURE TO COMPLY WITH A REPORTING REQUIREMENT SHOULD BE ASSESSED PER LSE FILING, RATHER THAN PER INSTANCE OR ERROR

The Draft Resolution should be clarified to state that scheduled penalties will be assessed per LSE *filing,* rather than for each instance or error. Table 1 in Appendix A states that the Scheduled Penalty for failure to comply with a Reporting Requirement in an IRP Proceeding is:

> $1,000 per *instance* of incomplete, incorrect or missing information, plus $500 per day for the first ten days after the deadline specified in the Correction Notice and $1,000 for each day thereafter, until the violation is corrected.[7]

The use of the phrase "per instance" may create unnecessary ambiguity. The Draft Resolution should be clarified to state that the Scheduled Penalty applies *per filing* with incomplete, incorrect or missing information. Otherwise, the Draft Resolution could be interpreted as requiring separate penalties for each individual error within a filing, which could result in duplicative penalties for the same type of error within a single filing. For example, there could be an input error that results in other errors elsewhere derived from a single input error. The Commission should therefore clarify the Draft Resolution such that the Scheduled Penalty applies *per filing*, rather than per error.

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[7] Draft Resolution, at A-5 (footnote omitted) (emphasis added).

VI. THE DRAFT RESOLUTION SHOULD BE CLARIFIED TO ALLOW AN APPEAL OF SCHEDULED PENALTIES IN THE EVENT THE RESPONDENT DEMONSTRATES THE CALCULATED CITATION AMOUNT IS NOT CONSISTENT WITH TABLE 1'S SCHEDULED PENALTIES

The Draft Resolution should be clarified to allow an appeal of scheduled penalties in the event the Respondent demonstrates the calculated citation amount is not consistent with Table 1's scheduled penalties. Section 2.6 in Appendix A states:

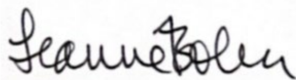
> A Respondent may either: (1) accept the citation; or (2) appeal the citation in accordance with the procedures set forth in Resolution ALJ-377 and/or other relevant authorities. Citations may be appealed on the grounds that a Specified Violation has not occurred, but the amounts of the Scheduled Penalties set forth in this Appendix are not subject to appeal.

The Commission should modify the Draft Resolution to clarify that the amounts of the scheduled penalties set forth in the Appendix are not subject to appeal, *unless the respondent demonstrates the calculated citation amount is not consistent with the Specified Violations and Scheduled Penalties required in Table 1*. For example, if the Scheduled Penalty is miscalculated based upon an incorrect number of days until a violation is corrected, a Respondent should be able to appeal the Scheduled Penalty. This will ensure Scheduled Penalty amounts are calculated consistent with the requirements in Table 1.

VII. CONCLUSION

CalCCA appreciates the Commission's consideration of the recommendations herein.

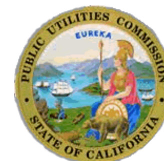
Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

cc via email:
Service Lists: R.20-05-003 and R.25-06-019



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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulations.	R.25-08-004

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE ORDER INSTITUTING RULEMAKING TO UPDATE DISTRIBUTION LEVEL INTERCONNECTION RULES AND REGULATIONS

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Jennifer Baak,
Senior Distribution Case Manager

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

October 20, 2025

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA respectfully makes the following recommendations in response to the OIR:

Scope:

- Modify Scoping Item 7[2] regarding the communications and interoperability of DERs to include consideration of costs and standards for communications and interoperability of non-IOU-owed DER and DERMS; and
- Modify Scoping Item 2 regarding interconnection processes to include the consideration of a penalty structure for IOU noncompliance with interconnection timelines.
- CalCCA highlights the importance to CCAs of the following preliminary scoping items and urges the Commission to include these items in the final Scoping Memo:
    - Reasonable cost allocation methodologies and fees for interconnection and interoperability (Scoping Items 4, 5, and 7); and
    - Update Rule 21 to reflect evolving technologies and adoption trends (Scoping Items 3 and 6).

Schedule:

- Divide the proceeding into the following two phases:
    - Phase One: Process Improvements and Technical Requirements Updates (Scoping Items 1, 2, 3, 6, and 8); and
    - Phase Two: Cost Issues (Scoping Items 4, 5, and 7).
- Consider workshops for the following issues:
    - Updates to Electrical Independence Tests (Scoping Item 1);
    - Interconnection timeline compliance and penalties (Scoping Item 2);
    - Cost allocation and fees (Scoping Items 4 and 5); and
    - Communications and interoperability standards and costs for non-IOU-managed DER and DERMS (Scoping Item 7).

---

[1] Acronyms used herein are defined in the body of this document.

[2] Scoping Items as used herein and in the body of this document are in reference to the preliminary scope of issues as set out in the OIR.

Coordination with Other Proceedings:

- Coordinate this proceeding with the recently opened *Order Instituting Rulemaking to Enhance Demand Response in California*,[3] to the extent it addresses relevant issues, including those considered by the CAISO Demand and Distributed Energy Market Integration WG.

[3] *Order Instituting Rulemaking to Enhance Demand Response in California*, Rulemaking (R.) 25-09-004 (Sept. 29, 2025) (Demand Response OIR): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M582/K072/582072320.PDF.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulations.	R.25-08-004

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON THE ORDER INSTITUTING RULEMAKING TO UPDATE DISTRIBUTION LEVEL INTERCONNECTION RULES AND REGULATIONS

The California Community Choice Association[4] (CalCCA) submits these opening comments pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[5] in response to the *Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulation*[6] (OIR), issued August 20, 2025, and the directives therein. The stated purpose of the OIR is to: (1) consider refinements to the interconnection of distributed energy resources (DER) under Electric Tariff Rule 21 (Rule 21) of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and

4 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

5 *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021): https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/rules-of-practice-and-procedure-may-2021.pdf.

6 *Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulation*, R.25-08-004 (Aug. 20, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M576/K867/576867418.PDF.

San Diego Gas & Electric Company (SDG&E) (collectively, IOUs),[7] and associated interconnection procedures concerning electric grid safety and reliability given the evolution of distributed technologies; (2) promote interconnection process transparency and certainty; and (3) contain ratepayer costs.[8]

I. INTRODUCTION

Rule 21 and the associated DER interconnection procedures play a significant role in the ability of community choice aggregators (CCA) to manage customer DER in a timely and cost-effective manner. CCAs provide generation service to over 14 million electric customers in more than 200 communities throughout California, playing a vital role in the deployment, and increasingly the operation, of DER. CCAs are in an ideal position to administer DER programs focused on serving local community needs given they are not-for-profit government agencies governed by publicly elected boards. Most CCAs offer programs to encourage the adoption of DER, including electric vehicles (EVs), solar photovoltaics (solar PV), battery energy storage systems (BESS), smart appliances, and other types of DER and beneficial electrification technologies.[9] These programs offer benefits to CCA customers and to the communities they serve, including customer bill savings, system-level peak load reduction, greenhouse gas (GHG) emissions mitigation, and enhanced grid reliability and resiliency. Many CCAs also make equity a focal point of their programs by targeting DER deployment to low-income and disadvantaged communities. CCAs are also beginning to incorporate load flexibility capabilities into their DER

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7 The OIR will also revisit the Rule 21 equivalent tariff rules of the small and multi-jurisdictional electric utilities (SMJUs). The CCAs only operate within the Joint IOUs' territories, and therefore CalCCA's participation in this proceeding will be limited to Rule 21 as it relates to the Joint IOUs.

8 OIR, at 1.

9 *See, e.g.*, Sonoma Clean Power's GridSavvy Rewards Program: https://sonomacleanpower.org/gridsavvy-rewards; San Diego Community Power's Solar Battery Savings Program: https://sdcommunitypower.org/solar-battery-savings/; and Clean Power Alliance's EV SmartCharge Program: https://cleanpoweralliance.org/evsmartcharge/.

programs, which are often managed by third-party aggregators or, in some cases, directly by the CCA via a DER Management System (DERMS).[10]

Given CCA management of customer DER, Rule 21 and the associated DER interconnection procedures have a significant impact on CCAs' ability to enroll, interconnect, and manage DER in their programs. CCAs require access to information about grid conditions through pricing or dispatch signals from IOU DERMS or Advanced Distribution Management Systems to support the efficient operation of DER and the grid. CCAs need certainty around interconnection times for both CCA-owned and customer-owned DER to improve program implementation and maximize the benefits of these resources. Fees and cost allocation methodologies must be equitable and reasonable to maximize customer participation in DER programs and to optimize grid capacity. In addition, Rule 21 updates may be necessary to incorporate new technologies and adoption trends, including non-exporting solar plus storage and vehicle-to-grid equipment.

CalCCA generally supports the preliminary scoping items set forth in the OIR with some modifications. The scoping items broadly address the following issues related to Rule 21 and interconnection procedures:

(1) Reform of electrical independence processes under Screens Q and R;

(2) IOU compliance with interconnection timeline benchmarks, dispute resolution processes, and utilizing Integration Capacity Analysis in project evaluations;

(3) Solutions and updates to technical requirements for interconnecting different equipment to the distribution grid;

(4) Upgrade cost sharing among multiple interconnection customers, and upgrade cost responsibility due to a Sustained Load Reduction;

(5) Modification to Rule 21 fees, cost allocation rules, and other Tariff implementation cost requirements;

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10 *See, e.g.,* MCE Clean Energy's Virtual Power Plant Pilot: https://mcecleanenergy.org/virtual-power-plant/.

(6) Alignment of Rule 21 with recent net billing tariff updates;

(7) Consideration of costs and standards for communications and interoperability of inverter-based resources; and

(8) IOU Wholesale Distribution Access Tariff processes and relationship to Rule 21.

As set forth below, CalCCA makes the following recommendations in response to the OIR:

- Scope:
  - Modify Scoping Item 7 regarding the communications and interoperability of DERs to include consideration of costs and standards for communications and interoperability of non-IOU-owed DER and DERMS; and
  - Modify Scoping Item 2 regarding interconnection processes to include the consideration of a penalty structure for IOU noncompliance with interconnection timelines.
  - CalCCA highlights the importance to CCAs of the following preliminary scoping items and urges the Commission to include these items in the final Scoping Memo:
    - Reasonable cost allocation methodologies and fees for interconnection and interoperability (Scoping Items 4, 5, and 7); and
    - Update Rule 21 to reflect evolving technologies and adoption trends (Scoping Items 3 and 6).
- Schedule:
  - Divide the proceeding into the following two phases:
    - Phase One: Process Improvements and Technical Requirements Updates (Scoping Items 1, 2, 3, 6, and 8); and
    - Phase Two: Cost Issues (Scoping Items 4, 5, and 7).
  - Consider workshops for the following issues:
    - Updates to Electrical Independence Tests (Scoping Item 1);
    - Interconnection timeline compliance and penalties (Scoping Item 2);
    - Cost allocation and fees (Scoping Items 4 and 5); and
    - Communications and interoperability standards and costs for non-IOU-managed DER and DERMS (Scoping Item 7).
- Coordination with Other Proceedings:
  - CalCCA recommends that the CPUC coordinate this proceeding with the recently opened OIR to Enhance Demand Response in California,[11] to the extent it addresses

[11] Demand Response OIR.

relevant issues, including those considered by the California Independent System Operator (CAISO) Demand and Distributed Energy Market Integration WG.

II. COMMUNICATIONS AND INTEROPERABILITY STANDARDS SHOULD EXPLICITLY INCORPORATE NON-IOU DERS PROVIDING GRID SERVICES

CalCCA requests Scoping Item 7 be modified to incorporate consideration of how Rule 21's communications and interoperability standards can encourage and enable *non-IOU-managed DER* to provide beneficial grid services. CCAs manage a variety of DER, mostly via customer programs and rates. Several CCAs have deployed or plan to launch DERMS platforms, enabling them to create and manage virtual power plants comprised of solar PV, BESS, EVs, and smart appliances. However, CCAs lack visibility into grid conditions and needs, and have historically focused their efforts on reducing costs, enhancing reliability, improving resiliency, reducing GHG emissions, and achieving other community goals. Without grid visibility, CCA-managed DER may inadvertently counteract IOU DERMS activity, potentially exacerbating capacity constraints.

Many third-party aggregators also manage DER that are not enrolled in IOU- or CCA-managed programs. DER managed by third parties may focus on providing backup power, maximizing customer savings, or enhancing the profitability of the DER provider. As DER proliferate, providers may not only compete to manage these devices at the premises level, but also at the device level within each premises, exacerbating the potential for conflicting operations. It should be noted that third-party aggregators and CCAs are engaging in stakeholder working groups at the CAISO to create opportunities for behind-the-meter DER to participate in the wholesale markets.[12] Further, in presentations to the California Future Grid Study workshop

[12] *See, e.g.*, CAISO's Demand and Distributed Energy Market Integration Stakeholder Initiative: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Demand-Distributed-Energy-Market-Integration.

series in the High DER proceeding,[13] the IOUs offered a vision for grid orchestration.[14] Arguing that grid orchestration is necessary for resolving conflicting grid needs, the IOUs stated that:

- Various local and system needs can be uncorrelated, or even worse, negatively correlated;
- By only meeting and orchestrating the needs of the energy system as a whole, constraints can be even exacerbated for the grid;
- Orchestration is required during those periods of conflict, whereby the needs of the hyper local [sic] are coordinated with the higher level and macro system; and
- Tariffs and/or policies may be needed to determine to support [sic] this orchestration, while also optimizing for customer value and considering customer preferences.[15]

The Joint IOUs Workshop Presentation presentation highlights the potential for conflict between the distribution and transmission grid needs but overlooks conflicting operational objectives of competing DER providers and aggregators at the distribution level. Grid orchestration must include *both* IOU- and non-IOU-managed DER to achieve the goals of optimizing distribution grid capacity and minimizing constraints. Focusing solely on IOU-managed DER would be akin to conducting only the brass and percussion instruments of an orchestra, while leaving out the stringed and woodwind instruments. Given the large number of customers served by CCAs and the variety of third-party DER providers and aggregators, open-source, standardized communication and interoperability protocols to enable coordination with non-IOU-managed DER are essential. The Commission should therefore modify Scoping Item 7 to encompass non-IOU-managed DER and DERMS.

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[13] *Order Instituting Rulemaking to Modernize the Electric Grid for a High DER Future* (High DER), R.21-06-017 (June 24, 2021): https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:R2106017.

[14] *High DER: Future Grid Study, Workshop One, Operational Needs*, R.21-06-017: (Feb. 8, 2024) (Joint IOUs Workshop Presentation): https://gridworks.org/wp-content/uploads/2024/02/2024-Future-Grid-Workshop-1-Joint-IOU-Presentation-FINAL.pdf.

[15] *Id.*, at slide 10.

III. A PENALTY STRUCTURE FOR NON-COMPLIANCE WITH INTERCONNECTION TIMELINE BENCHMARKS SHOULD BE CONSIDERED

CalCCA recommends including in Scoping Item 2 the consideration of a penalty structure as an additional measure to further improve IOU compliance with the interconnection timeline benchmarks established in D.20-09-035.[16] D.20-09-035 adopted proposals from Working Groups (WG) Two and Three, which were established in Phase 1 of the R.17-07-007 OIR to Consider Streamlining Interconnection and Distributed Energy Resources and Improvements to Rule 21.[17] Among the adopted proposals were several designed to "improve certainty regarding timelines for distribution upgrade planning, cost estimation, and construction" for interconnection-related upgrades.[18] In D.20-09-035, the Commission cited concerns about interconnection delays expressed by parties in the WG Three Final Report[19] that "developers cannot give reliable estimates to customers; customers may be required to carry their own facilities' loan or leasing costs for longer than reasonable or expected; and Utilities are not being held accountable."[20] These are serious concerns that must be investigated in this proceeding to ensure the IOUs are making their best efforts to adhere to established interconnection timelines.

D.20-09-035 required the IOUs to track timelines for specific interconnection tasks and established that no less than 95 percent of projects over 30 kilowatts meet all timelines starting

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[16] Decision (D.) 20-09-035, *Decision Adopting Recommendations from Working Groups Two, Three, and Subgroup*, R.17-07-007 (Sept. 24, 2020): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M347/K953/347953769.PDF.

[17] *Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21*, R.17-07-007 (July 13, 2017): https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:R1707007.

[18] D.20-09-035, at 82.

[19] *Working Group Three Final Report, CPUC Interconnection Rulemaking*, R.17-07-007 (June 14, 2019): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M309/K943/309943907.PDF.

[20] D.20-09-035, at 82-83.

two years after the commencement of the required tracking.[21] The Commission found the issue of financial penalties for not meeting these times to be premature when issuing D.20-09-035, stating that it "must first determine whether timeline certainty is improving."[22] The Commission further noted that it "may consider establishing a penalty structure in the future if it determines such a construct would support timely interconnection."[23]

On August 28, 2025, the California Solar and Storage Association (CalSSA) filed a complaint against PG&E and SCE, claiming their member companies "have suffered damages due to the gross and repeated violation of interconnection timelines in Rule 21."[24] The Complaint presents data to substantiate its claims that the IOUs have failed to meet the required deadlines. While CalCCA makes no claims as to the merits of CalSSA's Complaint, the issues it raises warrant further consideration. Regardless of the outcome of CalSSA's Complaint, the Commission should include in the scope of this OIR an examination of the IOU's compliance with the established timelines and the potential consequences and remedies for noncompliance, including a penalty structure.

IV. THE PROPOSED SCOPING ITEMS REGARDING REASONABLE COST ALLOCATION METHODOLOGIES AND FEES FOR INTERCONNECTION AND INTEROPERABILITY SHOULD BE ADOPTED

CalCCA supports including in the scope of this proceeding the investigation of reasonable and equitable cost allocation methodologies and fees for interconnecting DER and for establishing communication and interoperability between IOU- and non-IOU-managed DER and

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21 *Id.*, Ordering Paragraph (O¶) 22, at 212; and O¶ 28, at 215.

22 *Id.*, at 97.

23 *Ibid.*

24 Complaint 25-08-021, *California Solar & Storage Association (CALSSA), Complainant, vs. Pacific Gas and Electric Company (U39E) and Southern California Edison Company (U338E), Defendants*, (Aug. 28, 2025) (the Complaint), Appendix, at 1: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M580/K416/580416116.PDF.

DERMS. Regardless of who owns or manages their operation, DER can help mitigate rate increases, meet the state's electrification and GHG reduction goals, reduce energization times, optimize existing grid capacity, and minimize the need for grid upgrades. Given the potentially significant number of non-IOU managed DER, unreasonable fees and discriminatory cost allocation methodologies that discourage or limit their ability to provide beneficial grid services should be avoided.

CalCCA is aware of concerns that ratepayers may bear the costs of interconnection-related activities for individual projects and supports minimizing the cost burden on ratepayers. However, these costs must be considered alongside the load flexibility benefits such projects may provide, which could potentially reduce the need for costly grid upgrades. Any interconnection fees should be reasonable and proportionate to the size, complexity, and type of project. Likewise, costs related to protocol verification, performance testing, interoperability, and cybersecurity testing should not create barriers that could discourage non-IOU-managed DER and DERMS from providing beneficial grid services.

V. THE PROPOSED SCOPING ITEM REGARDING UPDATES TO RULE 21 TO REFLECT EVOLVING TECHNOLOGIES AND ADOPTION TRENDS SHOULD BE ADOPTED

CalCCA supports including in the scope of this proceeding updating Rule 21 to incorporate evolving technologies and adoption trends. More residential customers in California are installing non-exporting solar plus storage and/or non-exporting EVs, primarily from net energy metering tariff changes. Rule 21 must be updated to reflect these and other trends in the adoption of distributed generation technologies.

VI. SCHEDULE, PRIORITIZATION, SEQUENCING OF TOPICS

CalCCA proposes breaking the proceeding into two phases. The first phase could address topics related to process improvements and updates to technical requirements (Scoping Items 1,

2, 3, 6, and 8). The second phase could address issues related to costs (Scoping Items 4, 5, and 7). Workshops may be necessary on certain topics, including updates to the Electrical Independence Tests (Scoping Item 1), IOU accountability for meeting interconnection timelines (Scoping Item 2), cost allocation and fees (Scoping Items 4 and 5), and communications and interoperability standards for all DER and DERMS, including non-IOU-managed DER and DERMS (Scoping Item 7).

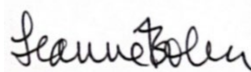
VII. PRELIMINARY DETERMINATIONS ON CATEGORIZATION, NEED FOR HEARING, AND COORDINATION WITH OTHER PROCEEDINGS

CalCCA has no objections to the preliminary determination on categorization of the proceeding as quasi-legislative (recognizing certain tracks of the proceeding, if established, may be categorized as ratesetting). Evidentiary hearings are also not anticipated to be needed. Finally, CalCCA recommends coordination with the recently opened Enhance Demand Response OIR in California,[25] to the extent it addresses relevant issues, including those considered by the CAISO DDEMI WG.

VIII. CONCLUSION

CalCCA appreciates the opportunity to submit these opening comments on the OIR and looks forward to engaging with the Commission and other stakeholders on the important issues raised therein.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

October 20, 2025

[25] *See* Demand Response OIR.

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

Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes.	R.25-06-019

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON ELECTRICITY PORTFOLIOS FOR 2026-2027 TRANSMISSION PLANNING PROCESS AND NEED FOR ADDITIONAL RELIABILITY PROCUREMENT

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Lauren Carr,
Senior Manager, Regulatory Affairs & Market Policy
Eric Little,
Director of Market Design

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

October 22, 2025

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APPENDIX A

SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends the Commission:

- ✓ Consider load forecasting uncertainties related to data centers and electrification embedded in the 2024 IEPR Demand Forecast when evaluating the recommended TPP Portfolios and proposed procurement order.
- ✓ Revise the recommended TPP portfolios by:
  - ✓ Updating the TPP portfolio selection framework to focus the base case on identifying the portfolio of least regrets (such as using a more conservative forecast through the Commission's reduced load sensitivity data center assumptions) and the sensitivity on transmission solutions beyond those identified by the least regrets portfolio (such as using the Planning Scenario forecast).
  - ✓ Maintaining the amount of in-state and OSW included in previous TPP portfolios to maintain consistency with previous TPPs and limit OOS wind in the base case to the amounts supported by SWIP-North (Idaho), TWE (Wyoming), and Sunzia (New Mexico).
  - ✓ Requesting the CAISO: (1) recommend upgrades identified in the sensitivity analysis dependent upon progress towards data center implementation milestones, results of OOS wind RFI in CAISO 2025-2026 TPP, and whether projects have multiple benefits (*e.g.,* policy/economic needs, or load/generation interconnection); and (2) consider refinements to the commercial interest criteria necessitated by the new interconnection application intake process established in the IPE 2023.
- ✓ Consider that ad hoc procurement orders are not the most effective mechanism to ensure reliability, given their potential negative affordability impacts on LSEs and ratepayers, and prioritize the careful adoption of the programmatic framework for the RCPPP.
- ✓ Adopt the following if the Commission moves forward with an ad hoc procurement order:
  - Proceed cautiously and account for the significant uncertainties baked into the 2024 IEPR Demand Forecast related to data centers and electrification to avoid over-procurement and the affordability implications for ratepayers.
  - Consider both Commission staff's and CalCCA's needs scenarios demonstrating a significantly reduced need with load uncertainties regarding data centers and electrification incorporated.
  - Order procurement of 2,000 MW for the first tranche (2029-2030) and 2,000 MW for the second tranche (2031-2032), then re-evaluate in 2027

[1] Acronyms used herein are defined in the body of this document.

the need for the additional 2,000 MW of procurement ordered in Q1 2028 to occur in the second tranche.

- Allow flexible compliance methods, such as requiring procurement in tranches and extending the rules adopted in D.25-09-007[2] to apply to any procurement order.
- Take measures to ensure that an LSE's net position is not revealed to potential sellers.
- Work via the TED task force to ensure that resources that have been procured can achieve their COD.
- Order procurement for generic capacity only, using SOD accounting.
- Apply resource eligibility consistent with prior MTR orders for generic capacity and allow capacity from repowers to count, or in the alternative serve as baseline swaps.
- Allocate the procurement requirements using the most recently available peak load ratio share for each tranche, using the MTR baseline and allowing LSEs to count excess MTR and Supplemental MTR procurement.
- Refrain from ordering central procurement or requiring procurement within local capacity areas.
- Ensure rules established for the MTR and Supplemental MTR orders are carried over or modified when necessary to apply to any procurement order resulting from this Ruling, including allowing LSEs to trade obligations, studying and clarifying how a procurement order would impact central procurement of LLT resources, and clarifying baseline swap rules.

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[2] Decision (D.) 25-09-007, *Decision Granting, with Modifications, Southern California Edison Company's Petition for Modification of Decisions 23-02-040 and 24-02-047*, R.20-05-003 (Sept. 26, 2025) at 20: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M581/K576/581576925.PDF.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes.	R.25-06-019

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON ELECTRICITY PORTFOLIOS FOR 2026-2027 TRANSMISSION PLANNING PROCESS AND NEED FOR ADDITIONAL RELIABILITY PROCUREMENT

California Community Choice Association[3] (CalCCA) submits these comments pursuant to the *Administrative Law Judge's Ruling Seeking Comments on Electricity Portfolios for 2026-2027 Transmission Planning Process and Need for Additional Reliability Procurement*[4] (Ruling), dated September 30, 2025.

I. INTRODUCTION

California's energy landscape faces significant evolution resulting from the emergence of large loads including data centers, changes in federal policy, and ongoing technology innovation. In both transmission and procurement planning, the California Public Utilities Commission (Commission) and other California energy agencies continue efforts to ensure a reliable transition to a clean energy future while also safeguarding customer affordability. The Ruling invites

[3] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[4] *Administrative Law Judge's Ruling Seeking Comments on Electricity Portfolios for 2026-2027 Transmission Planning Process and Need for Additional Reliability Procurement*, Rulemaking (R.) 25-06-019 (Sept. 30, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M582/K082/582082526.PDF.

comments on two sets of Commission staff recommendations: (1) a base and sensitivity portfolio for the California Independent System Operator (CAISO) to study in its 2026-2027 Transmission Planning Process (TPP); and (2) a Commission order for 6,000 megawatts (MW) of load-serving entity (LSE) procurement between 2029 and 2032. The following summarizes CalCCA's comments herein.

A. Load Forecast Uncertainty Must Be Considered When Evaluating the Recommended TPP Portfolios and Procurement Order

As a preliminary matter, the Commission's recommendations must be analyzed in the context of various factors including the unprecedented increased load predicted in the Demand Forecast established by the California Energy Commission's (CEC) 2024 Integrated Energy Policy Report (IEPR) Update.[5] This increase, in large part due to data centers, other large loads, and electrification, has been scrutinized not only by the CEC and other state and federal regulators, but also by stakeholders and the media which have widely noted the difficulty of concluding whether these loads will actually materialize as discussed in detail herein. In addition, changes in federal electric vehicle (EV) policies and incentives may result in a less significant increase in EV adoption (and electric load) than assumed in the forecast. CalCCA therefore provides its comments on the TPP and procurement recommendations in the context of these and other recognized system planning challenges.

B. TPP Portfolios Should Drive Low Risk and Low-Cost Transmission Investment Based on Realistic Expectations About New Resource Build

The Commission should update the framework for the TPP portfolio selection to focus its base case on identifying the portfolio that results in "Category One" transmission solutions of "least regrets," which the CAISO defines as "… transmission solutions identified as critical in a

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[5] CEC 24-IEPR-01, adopted 2024 IEPR Update (Oct. 29, 2025): https://www.energy.ca.gov/publications/2024/2024-integrated-energy-policy-report-update.

significant percentage of the stress scenarios," and "…solutions based on their low risk of being underutilized because they appear as needed across different generation development scenarios or rank high based on the commercial, economic, and environmental criteria."[6] The sensitivity case should be focused on identifying "Category 2" transmission solutions, which the CAISO defines as "[t]ransmission solutions that could be necessary to achieve an identified public policy, but which the CAISO has not found to be necessary in the current transmission plan,"[7] to ensure robust planning under uncertain scenarios.

Specifically, the Commission should modify the base case to use a more conservative forecast of data center load, such as the Commission's reduced load sensitivity data center assumptions, and use the 2024 IEPR Planning Scenario for the sensitivity case. The Commission should also maintain the amount of in-state and offshore wind (OSW) included in previous TPP portfolios in the base case and limit out-of-state (OOS) wind in the base case to the amounts supported by the SWIP-North (Idaho), TWE (Wyoming), and Sunzia (New Mexico) projects. The Commission should then request that the CAISO recommend upgrades identified in the sensitivity analysis dependent upon: (1) more up-to-date information on progress towards data center implementation milestones; (2) the results of the OOS wind request for information (RFI) in the CAISO 2025-2026 TPP; and/or (3) whether projects have multiple benefits (*e.g.,* policy/economic needs, or load/generation interconnection).

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[6] The CAISO describes Category One transmission solutions as those that the transmission planning process will recommend to the CAISO Board for approval. *See Comments of the California Independent System Operator Corporation on Advanced Notice of Proposed Rulemaking,* FERC Docket No. RM21-17-000 (Oct. 12, 2021), at 26-27: https://www.caiso.com/Documents/Oct12-2021-Comments-AdvanceNoticeOfProposedRulemaking-BuildingTransmissionSystemoftheFuture-RM21-17.pdf.

[7] *Id.* at 26.

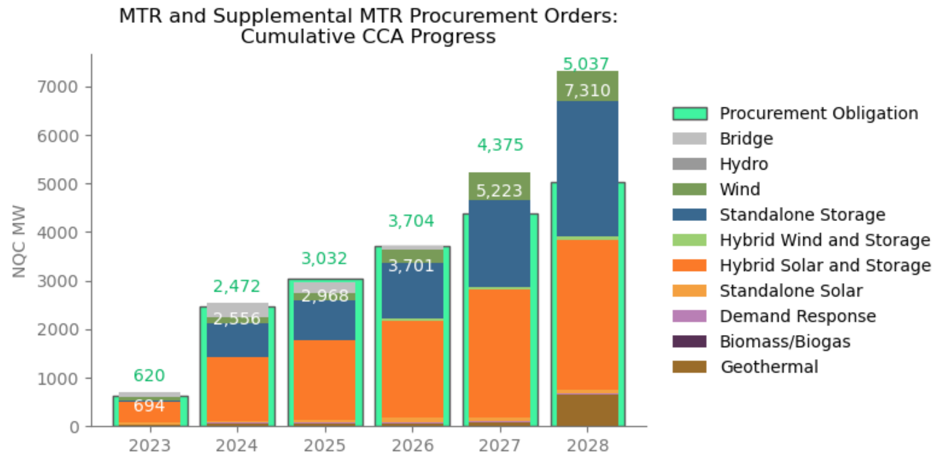
C. While Ad Hoc Procurement Orders Should be Avoided and the Development of a Robust RCPPP Should be Prioritized, if the Commission Issues a Procurement Order it Should Proceed Cautiously Based on Uncertain Load Forecasts

1. Ad-hoc Procurement Orders are not the Most Effective Mechanism for Bringing New Resources Online to Address Reliability

Ad-hoc and unpredictable procurement orders are not the most effective mechanism for bringing new resources online and can markedly drive-up costs for procuring LSEs and their customers at a time when customer affordability continues to be a significant challenge. While the Commission proposes 6,000 MW of additional procurement by LSEs between 2029 and 2032 based on Commission staff's needs analysis, the Commission should recognize that a *need for procurement* is not synonymous with a *need for a procurement order.* That is, an ad hoc procurement order is *not* the only way to bring capacity online. CCAs were fundamentally formed to procure generation to meet the reliability needs of the communities they serve and remain committed to doing so absent a Commission directive for procurement. For example, CCAs are already committed to procuring new clean resources to support reliability needs and in aggregate have over 18,000 MW of nameplate capacity with online dates of 2018-2028 under long-term contract.[8] As of June 2025, CCAs in aggregate are making significant progress towards *exceeding* mid-term reliability (MTR) requirements, as shown in **Figure 1**.

[8] *See* CalCCA website, information on CCA PPAs: https://cal-cca.org/cca-renewable-energy-map-and-list-of-ppas/.

Figure 1: MTR and Supplemental MTR Procurement Progress as of June 2025



In addition, ad hoc procurement orders can serve as policy shocks that unnecessarily shift market power to developers, leading to increased LSE costs and contributing to the growing affordability crisis. Clean energy development is currently facing significant barriers outside the control of the LSEs conducting procurement, including supply chain delays, interconnection bottlenecks, permitting delays, import tariffs, and other recent federal policy changes. The impact of these barriers on ongoing LSE procurement efforts, including the cost impacts to ratepayers, may be exacerbated by an ad hoc procurement order.

The Commission should therefore make the robust and careful development of the Reliable and Clean Power Procurement Program (RCPPP), including establishing a working group process, its highest near-term priority so that it has a programmatic way to establish LSE procurement requirements for future needs. Identifying procurement needs far in advance and on a regular cadence will allow for orderly procurement, avoid market disruption, keep costs low, and mitigate affordability impacts.

2. If the Commission Issues an Ad Hoc Procurement Order, It Should Recognize the Impact of Load Growth Uncertainty When Setting Procurement Targets and Timing

If the Commission moves forward with an ad hoc procurement order, it should recognize the impact of load growth uncertainty when setting procurement targets and timing, as discussed in detail herein. CalCCA's needs analysis, discussed below, demonstrates a need of roughly the same magnitude *if the load growth in the CEC's 2024 IEPR Demand Forecast materializes*. If the load growth *does not materialize,* however, the procurement order's need determination may be overstated. Indeed, the Commission's "Reduced Load" scenario (reflecting recent federal policy changes, and uncertainty in data center load and electrification) predicts roughly a *third* of the need recommended by the Ruling (2,012 MW for the Reduced Load scenarios versus 6,000 MW). CalCCA's own study with a Low Demand Growth sensitivity case (predicting a need of only 1,932 MW with incorporating low data center and EV rates) also points to the need for caution. Procurement orders that exceed the load growth that in fact materializes will result in unnecessary costs to customers who are already experiencing an affordability crisis.

3. The Commission Should Proceed Cautiously with any Procurement Order and Provide LSEs With Flexibility to Procure in Two Tranches of 2,000 MW Each, with an Additional Needs Analysis for the Final 2,000 MW

The Commission should minimize cost impacts of any procurement order by building in compliance flexibility by: (1) modifying the recommended annual compliance requirements to multi-year tranches to accommodate shifts in commercial operations dates (COD) of contracted resources; and (2) re-evaluating the need in the later tranche once more information is known about whether forecasted large loads will materialize, and with updated peak load allocations. Specifically, CalCCA recommends in the Comments below that the Commission split the procurement order into two tranches. The first tranche for 2029-2030 should require 2,000 MW

(rather than 3,000 MW as set forth in the Ruling). The second tranche for 2031-2032 should initially require 2,000 MW (again, 1,000 MW less than set forth in the Ruling). The Commission should then perform an incremental needs assessment in 2027 to determine whether any more procurement up to an additional 2,000 MW is necessary for the second tranche (2031-2032). The Commission should also adopt various flexible compliance rules established in the MTR and later orders, as detailed below.

D. Summary of CalCCA Recommendations

In summary, CalCCA recommends the Commission:

- ✓ Consider load forecasting uncertainties related to data centers and electrification embedded in the 2024 IEPR Demand Forecast when evaluating the recommended TPP Portfolios and procurement order.
- ✓ Revise the recommended TPP portfolios by:
  - Updating the TPP portfolio selection framework to focus the base case on identifying the portfolio of least regrets (by using a more conservative forecast through the Commission's reduced load sensitivity data center assumptions) and the sensitivity on transmission solutions beyond those identified by the least regrets portfolio (by using the Planning Scenario forecast).
  - Maintaining the amount of in-state and OSW included in previous TPP portfolios to maintain consistency with previous TPPs and limit OOS wind in the base case to the amounts supported by SWIP-North (Idaho), TWE (Wyoming), and Sunzia (New Mexico).
  - Requesting the CAISO: (1) recommend upgrades identified in the sensitivity analysis dependent upon progress towards data center implementation milestones, results of OOS wind RFI in CAISO 2025-2026 TPP, and whether projects have multiple benefits (*e.g.,* policy/economic needs, or load/generation interconnection); and (2) consider refinements to the commercial interest criteria necessitated by the new interconnection application intake process established in the Interconnection Process Enhancements (IPE) 2023.
- ✓ Consider that ad hoc procurement orders are not the most effective mechanism to ensure reliability, given their potential negative affordability impacts on LSEs and ratepayers, and prioritize the careful adoption of the programmatic framework for the RCPPP.
- ✓ Adopt the following if the Commission moves forward with an ad hoc procurement order:

- Proceed cautiously and account for the significant uncertainties baked into the 2024 IEPR Demand Forecast related to data centers and electrification to avoid over-procurement and the affordability implications for ratepayers.
- Consider both Commission staff's and CalCCA's needs scenarios demonstrating a significantly reduced need with load uncertainties regarding data centers and electrification incorporated.
- Order procurement of 2,000 MW for the first tranche (2029-2030) and 2,000 MW for the second tranche (2031-2032), then re-evaluate in 2027 the need for the additional 2,000 MW of procurement ordered in Q1 2028 to occur in the second tranche.
- Allow flexible compliance methods, such as requiring procurement in tranches and extending the rules adopted in D.25-09-007 to apply to any procurement order.
- Take measures to ensure that an LSE's net position is not revealed to potential sellers.
- Work via the Tracking Energy Development (TED) task force to ensure that resources that have been procured can achieve their COD.
- Order procurement for generic capacity only, using slice-of-day (SOD) accounting.
- Apply resource eligibility consistent with prior MTR orders for generic capacity and allow capacity from repowers to count, or in the alternative serve as baseline swaps.
- Allocate the procurement requirements using the most recently available peak load ratio share for each tranche, using the MTR baseline and allowing LSEs to count excess MTR and Supplemental MTR procurement.
- Refrain from ordering central procurement or requiring procurement within local capacity areas.
- Ensure rules established for the MTR and Supplemental MTR orders are carried over or modified when necessary to apply to any procurement order resulting from this Ruling, including allowing LSEs to trade obligations, studying and clarifying how a procurement order would impact central procurement of long-lead time (LLT) resources, and clarifying baseline swap rules.

II. UNCERTAINTY REGARDING THE 2024 IEPR DEMAND FORECAST MUST INFORM EVALUATION AND RECOMMENDATIONS FOR THE PROPOSED 2026-2027 TPP PORTFOLIOS AND PROCUREMENT ORDER

Uncertainties embedded in the 2024 IEPR Forecast must inform evaluation and recommendations for the Ruling's proposed 2026-2027 TPP portfolios and procurement order. The

Commission uses elements of the CEC Demand Forecast for planning and procurement, as agreed in the MOU between the California energy agencies.[9] The recommended TPP 2026-2027 base case portfolio includes:

> [A] general increase in selected capacity due to the increased load in the 2024 IEPR load forecast, which has gross peak that is approximately 4.4 GW higher than the previous forecast during the middle of the 2030 decade.[10]

In addition, the Ruling states the procurement needs analysis was conducted by Commission staff in response to, among other factors, the "significant load growth now being forecasted in 2028-2032 in the CEC's 2024 IEPR demand forecast."[11] CalCCA appreciates the Commission's attention to the high load growth and data center uncertainties analyzed through the reliability sensitivities.[12] Based on review of data and materials questioning forecasts regarding nascent data center load, as well as potential reduced electrification, the Commission should take a cautious approach to requiring transmission build and/or ordering procurement. Given the uncertainty as addressed in detail below, CalCCA recommends in response to the Ruling questions in Section III. that the Commission: (1) update the framework for the TPP portfolio selection to focus the base case portfolio on identifying the portfolio of least regrets, and the sensitivity case portfolio on transmission solutions beyond those to support the least regrets portfolio; and (2) if a procurement

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[9] *Memorandum of Understanding between the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) and the California Independent System Operator (ISO) Regarding Transmission and Resource Planning and Implementation* (Dec. 2022) (MOU): https://www.caiso.com/documents/iso-cec-and-cpuc-memorandum-of-understanding-dec-2022.pdf.

[10] Ruling, at 14.

[11] Ruling, at 24; *see also* Ruling, at 25 (stating that the first basic assumption for the needs analysis is that "the load forecast was updated based on the 2024 IEPR assumptions"). The Ruling also notes that its needs analysis responds to RCPPP comments from parties, and American Clean Power-California's (ACP-CA) Motion to require additional near-term procurement. *See* R.20-05-003, *American Clean Power - California Motion to Amend the Scoping Memo to Include an Additional Track for Expedited Procurement* (July 21, 2025) (ACP-CA Motion): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M573/K432/573432213.PDF.

[12] *See* Ruling, at 32.

order is issued, issue procurement in two tranches – 2,000 MW for Tranche One (2029-2030), and 2,000 MW for Tranche Two (2031-2032), with a reassessment in 2027 to determine by Q1 2028 whether an additional 2,000 MW of procurement for 2031-2032 is necessary.

A. The CEC 2024 Demand Forecast is Based on Uncertain Demand

The load growth anticipated by the CEC's 2024 Demand Forecast is partly based on uncertain data center demand, as acknowledged in the 2024 IEPR Update, and discussed by regulators, stakeholders, and widely reported in the media. Indeed, a recent report highlighted unique incentives for data center customers frustrating attempts to forecast this load: "Some estimate that speculative interconnection requests could be five to ten times more than the actual number of data centers, as data centers "shop around" for the fastest interconnection opportunities and cancel data center projects in oversupply."[13] In addition, given the magnitude of some data center interconnection requests, uncertainties related to a data center's actual peak load could materially impact the forecast. Concerns regarding the certainty of the data center forecast are demonstrated by: (1) statements by CEC staff in their development of the 2024 Demand Forecast; (2) the fact that the forecast was developed through input from limited sources; and (3) doubts surrounding a 70 percent "confidence level" applied by the CEC regarding whether data center load will materialize.

First, CEC staff acknowledged the uncertainties involved with their data center certainty analysis, stating during the 2024 Demand Forecast development that "[t]his has been a continually evolving process, as we learn more every day. The data center methodology will be improved next year."[14] The 2024 IEPR Update states:

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[13] *Fast, Flexible Solutions for Data Centers,* Rocky Mountain Institute (July 17, 2025): https://rmi.org/fast-flexible-solutions-for-data-centers/.

[14] CEC Docket No. 24-IEPR-3, Data Center Forecast presentation, Jenny Chen (Dec. 23, 2024), at 2: https://www.energy.ca.gov/sites/default/files/2024-12/Data_Center_Forecast_Update_ada.pdf.

> Data centers will remain an area of focus for the 2025 IEPR forecast. Staff will continue to track new information, collaborate with utilities to monitor applications for new data centers, and ask for stakeholder feedback on inputs and assumptions. Staff will adjust inputs and assumptions for the 2025 IEPR forecast based on the most recent data.[15]

CalCCA provided extensive comments in response to a 2025 IEPR Commission Workshop on the need to improve forecasting of large loads including data centers.[16] CalCCA recommends increased transparency, collaboration, and certainty in the large load and data center forecasting process, including incorporating information from CCAs as default generation providers on the certainty and assumptions regarding large loads.[17] In addition, CalCCA recommends that the CEC initiate a dedicated workstream and procedural path to engage stakeholders in addressing the many challenges associated with forecasting as a result of the unique characteristics of large loads.[18]

Second, rather than rely on historical data to forecast data center load for the 2024 IEPR Update, the CEC used information provided by Silicon Valley Power, the City of Palo Alto, the City of San Jose, PG&E, and SCE from applications submitted for new data center loads.[19] In particular, PG&E and SCE provided *estimates* of data center capacity from interconnection applications in various stages of development from project inquiries, active applications pre- and post-engineering studies, and projects in transmission and distribution planning. Other than the City of San Jose, which has its own CCA (San Jose Clean Energy), CCAs were generally not part of the conversations regarding data center estimates.

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15 2024 IEPR Update, at 21.

16 CEC Docket No. 25-IEPR-03, *California Community Choice Association's Comments on the August 6, 2025, IEPR Commissioner Workshop on Energy Demand Forecast Inputs and Assumptions* (Aug. 20, 2025): https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=25-IEPR-03.

17 *Id.* at 3-5.

18 *Id.* at 5-8, 10-11.

19 2024 IEPR Update, at 19.

Third, the CEC applied a 70 percent "confidence level" as advanced by Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) regarding data centers coming online "[g]iven uncertainties associated with applications for new loads, including project complete date[s] and final installed capacity."[20] However, in response to an October 2025 Administrative Law Judge (ALJ) Ruling in PG&E's 2026 Energy Resource Recovery Account (ERRA) Forecast case, which identified "various inconsistencies and missing information" regarding the certainty rate, PG&E acknowledged that the 70 percent rate is not unique to data centers, but instead is based on SCE's conversion rate for *all customers in SCE's interconnection queue.*[21]

In fact, PG&E recently reversed its use of the 70 percent conversion rate in its ERRA Forecast with a completely new formula resulting in a lower forecast for data centers.[22] In making this change, PG&E notes "new data on the data center interconnection application queue in addition to uncertainty associated with the nascent field of data center forecasting led PG&E to update the data center forecast for the 2026 load forecast."[23] PG&E acknowledges the difficulties in determining a data forecast, noting that "[t]o the point of data center forecasting nascency: prior to this Fall Update, PG&E had only produced a data center forecast once. Similarly, the [CEC] has only produced a data center forecast once."[24]

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20 *Ibid.*; *see also* CEC Demand Analysis Working Group (DAWG) Meeting, Data Center Forecast presentation, Jenny Chen (Dec. 23, 2024), at 4 (CEC staff applied a 70 percent confidence level to data center applications with "completed or to be completed" engineering studies (but not yet in transmission and distribution planning)).

21 *See* Application (A.) 25-05-011, *Administrative Law Judge's Ruling Requiring Additional Information* (Sept. 9, 2025); *see also* A.25-11-011, *Administrative Law Judge's Ruling Requiring Additional Information* (Oct. 6, 2025).

22 A.25-11-011, PG&E October Update Testimony, at 7.

23 *Ibid.*

24 *Id.* at 7*,* n.10.

PG&E therefore added "a new constraint" of limiting forecasted load only to projects in the interconnection queue that had reached "an advanced level of maturity."[25] PG&E's original Load Forecast had applied the 70 percent rate and assumed new data center load from projects with an active application and completed or in-progress engineering studies.[26] The new constraint "only assumes data center load from projects for which PG&E has identified a Business Case Customer Required Operative Date (BC CRODT) by year-end 2026:

> The BC CRODT is the date that PG&E has agreed to in the business case with the customer to put the project in service. . . The BC CRODT can be interpreted as the deadline that PG&E and the customer have agreed upon for energization. It represents [PG&E's] best professional judgment of energization date [by year-end 2026]. With this approach, PG&E no longer applies [the 70 percent confidence factor].[27]

In addition, PG&E admitted that:

> [t]o calculate an application [confidence] rate, rather than examining PG&E's pipeline of incomplete projects, it would be preferable to examine PG&E's historical list of completed data center projects and the historical list of withdrawn projects over a comparable timeframe. *PG&E does not have the information to calculate such a rate at this time.*[28]

As a result of PG&E's new equation, PG&E "reduc[ed] . . . the number of data center applications that PG&E forecasts for 2026" and reduced the forecasted load.[29] Even though PG&E now admits that the 70 percent conversion rate for data centers is not accurate, the 2024 IEPR Demand Forecast utilized that conversion rate. As a result, one of the factors underlying the Ruling

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25 *Id.* at 7.

26 *Ibid.*

27 *Id.* at 7-8.

28 *Id.* at 9.

29 *Id.* at 10. PG&E similarly noted in rebuttal testimony in its application proceeding requesting approval of a new transmission interconnection tariff for large loads that "…nationally, utilities and policymakers are struggling with forecasting data center development given the economic and regulatory landscape. PG&E is no different and although we are constantly refining our forecast of data center and transmission-level customer load, these loads are subject to change." *See* A.24-11-007, *PG&E Application for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service,* Rebuttal Testimony (Aug. 19, 2025), at 8.

on the TPP portfolios and procurement order is incorrect. Therefore, the Commission must consider the inaccuracy and significant uncertainties identified by PG&E and many other parties when assessing future transmission and/or procurement need.

B. The Federal Energy Regulatory Commission and the CAISO are Increasingly Concerned about Large Load Forecasting Uncertainties

In addition to the uncertainty of the CEC's forecast, in a recent letter to regional transmission organizations and independent system operators including the CAISO, FERC Chairman Rosner highlights challenges and opens a dialogue regarding large load interconnections:

> Our experience to date tells us that large loads, such as data centers, have characteristics that call for new and improved forecasting methods. Given the size and volume of new large load interconnection requests, I'm optimistic that utilities have an opportunity to apply similar criteria to those currently used to assess the commercial readiness of large projects in the generator interconnection queue. These objective criteria include observable milestones such as contracts, financial security deposits, and physical site control.[30]

In response, the CAISO letter describes the CEC load forecasting process, acknowledging that accuracy regarding large load forecasting is still a work in progress:

> To manage uncertainty around large load interconnection requests, the CEC currently groups projects into different tiers based on their likelihood of materializing. However, the CEC continues to collaborate with utilities and industry experts to evolve its approaches to ensure against double-counting large load interconnection requests.[31]

In short, accurate large load forecasting has been identified as a unique challenge both at the federal and state levels.

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[30] FERC Chairman Rosner's Letter to the RTOs/ISOs on Large Load Forecasting (Sept. 18, 2025): https://www.ferc.gov/news-events/news/chairman-rosners-letter-rtosisos-large-load-forecasting.

[31] CAISO President and Chief Executive Officer Elliot Mainzer response to FERC Chairman Rosner letter (Oct. 13, 2025): https://www.ferc.gov/media/caiso-response-chairman-david-rosners-09192025-letter-re-large-load-forecasting-americas.

C. Federal Policies May Result in Reduced Electrification

In addition to uncertainties related to data center load, changes in federal EV policies and incentives may result in a 32 percent reduction in EV adoption than assumed in the forecast.[32] Therefore, the Commission should also bear in mind changes in federal policy that may impact inputs and assumptions in the 2024 IEPR Demand Forecast.

D. CCA Load Forecasts Should be Incorporated into the Load Forecasting Process

As noted above, the CEC acknowledged that the investor-owned utilities (IOU) and municipal utilities, but not other key stakeholders including CCAs, electric service providers, or data center customers, provided the bulk of the input for large load forecasting. Although the amount of CCA load has grown materially, the CEC's forecasting methodology has not been modified to incorporate CCA insights early in the process. In fact, for the 2024 IEPR Demand Forecast, the CEC primarily used IOU information, which the IOUs compiled through their own modeling and consultations with their "internal subject matter experts."[33] As noted in Section II.A. above, it appears the IOUs no longer believe these assumptions are reasonable, with PG&E acknowledging that its forecasting and applied conversion rate was based on all load in another IOUs' interconnection queue. CalCCA appreciates CEC staff's recent comments during an August 2025 IEPR workshop that they "should have time to build in more collaboration" from all LSEs

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[32] Buckberg, E. and C. Cole 2025. "Trump EV Policy Overhaul: What Will Happen to EV Adoption, Emissions, and the Fiscal Balance?" Policy Brief. Harvard University (Trump EV Policy): https://salatainstitute.harvard.edu/wp-content/uploads/2025/03/Policy-Brief_Trump-EV-Policy-Overhaul.pdf.

[33] CEC DAWG Meeting, PG&E Data Center Forecasting presentation, Jenny Conde (July 16, 2025), at 6.

during the 2025 IEPR Forecast process.[34] The promised collaboration will allow for the CEC to test the IOUs' inputs and assumptions and provide a more informed forecast of these uncertain loads.

Given minimal input from CCAs in the 2024 CEC IEPR Update process, the CCA load forecasts provided in this proceeding in response to the ALJ ruling allowing LSEs to "update their load forecasts" for IRP filings are all the more important.[35] While the IOUs objected to the CCAs providing any input to load forecasting beyond what was provided in the 2024 CEC IEPR Demand Forecast, many CCAs have provided additional load forecasting information that should be considered by this Commission in its analysis of individual IRP filings, as well as any needs analysis.[36] Indeed, CCAs in PG&E's service territory have recently been given access to PG&E transmission interconnection applications and customer information, which is empowering CCAs to connect with new customers and to use these relationships to provide informed feedback on the load forecast including the likelihood, timing, and operating characteristics of new loads.[37] The revised forecasts submitted by CCAs thus reflect more realistic locational load growth expectations than the disaggregated load forecast from the CEC's 2024 IEPR, as they incorporate

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[34] 25-IEPR-03, CEC Staff comments during August 6, 2025, IEPR Commissioner Workshop on Energy Demand Forecast.

[35] R.25-06-019, *Administrative Law Judge's Ruling Establishing Process for Finalizing Load Forecasts and Greenhouse Gas Emissions Benchmarks for Individual Integrated Resource Plan Filings* (Aug. 4, 2025) (Load Forecast Ruling): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M574/K962/574962704.PDF.

[36] The updated load forecasts were filed in this docket on September 11, 2025, in response to the Load Forecast Ruling by CCAs including Central Coast Community Energy, Clean Power Alliance of Southern California, Pico Rivera Innovative Municipal Energy, Silicon Valley Clean Energy, City of Palmdale, Marin Clean Energy, Santa Barbara Clean Energy, Valley Clean Energy Alliance, Ava Community Energy, San Jose Clean Energy, City of Pomona, Pioneer Community Energy, Orange County Power Authority, Lancaster Choice Energy, Rancho Mirage Energy Authority, San Jacinto Power, Peninsula Clean Energy Authority, CleanPowerSF, and Apple Valley Choice Energy. Redwood Coast Energy submitted on October 3, 2025, a Motion for Leave to Accept a Late-Filed Response, and a response to the Load Forecast Ruling.

[37] *See* D.25-07-039, *Decision Partly Granting and Partly Denying Pacific Gas and Electric Company's Motion for Interim Implementation of Electric Rule Number 30,* A.24-11-007 (July 24, 2025) (requiring PG&E to provide interconnection applications and related information to inform generation procurement decisions by CCAs for large load customers).

data specific to CCA service territories. Deviations between what CCAs are forecasting using data specific to their service territories and the load forecasted in the 2024 IEPR further underscore the risk that any procurement order based on the 2024 IEPR could result in costly over-procurement. As situations regarding large loads and electrification adoption are rapidly evolving, CCA input will only serve to increase the accuracy of large load and electrification forecasting, as well as inform transmission and procurement needs.

E. Large Load and Electrification Forecasting Uncertainties Should Inform a Cautious Approach to TPP and Procurement Recommendations

Overall, the large load and electrification forecasting uncertainties must be considered in system planning. As set forth below in response to the Ruling questions, CalCCA recommends that the Commission: (1) update the framework for the TPP portfolio selection to focus the base case on identifying the portfolio of least regrets, and the sensitivity case on transmission needs beyond those to support the least regrets portfolio; and (2) order any procurement in two tranches – 2,000 MW for Tranche One (2029-2030), and 2,000 MW for Tranche Two (2031-2032), with a needs analysis conducted in 2027 regarding an additional 2,000 MW for 2031-2032 to inform a potential revised needs determination for Tranche Two in Q1 2028.[38]

III. QUESTIONS RELATED TO THE 2026-2027 TPP RECOMMENDATIONS

1. Please comment on the updated Framework for TPP Portfolio Selection and recommend any changes.

The Commission should update the framework for the TPP portfolio selection to focus: (1) the base case on identifying the portfolio of least regrets; and (2) the sensitivity case on transmission needs beyond those to support the least regrets portfolio. Currently, the Commission designs base case portfolios "to reflect Commission policy guidance, including meeting the

[38] If RCPPP can be implemented in advance of the reassessment of the second tranche need, the RCPPP requirements should supersede the procurement order requirements as stated in response to question 24.

reliability standard and achieving GHG reduction targets."[39] The base case portfolios "go directly to the CAISO Board of Governors for approval for investment."[40] The Commission designs sensitivity case portfolios to either: (1) support a "least regrets" approach that provides a reasonable range of future scenarios that can be linked to the base case, as further described below; or (2) gather additional information to potentially support future portfolio development and explore incremental optionality or risk.[41] Sensitivity cases "do not go directly to the CAISO Board for approval, but often help inform future base case portfolios."[42] This process should be revisited to account for current uncertainty in assumptions, given the emergence of new large loads, changes in federal policy, and new technology innovation.

While CalCCA supports focusing on "least regrets" planning, the Commission should focus its base case portfolio on identifying "Category One" transmission solutions of "least regrets," which the CAISO defines as "… transmission solutions identified as critical in a significant percentage of the stress scenarios," and "…solutions based on their low risk of being underutilized because they appear as needed across different generation development scenarios or rank high based on the commercial, economic, and environmental criteria."[43] The sensitivity case should be focused on identifying "Category 2" transmission solutions, which the CAISO defines as "[t]ransmission solutions that could be necessary to achieve an identified public policy, but which the CAISO has not found to be necessary in the current transmission plan,"[44] to ensure robust

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39 Ruling, at 6.

40 *Ibid.*

41 *Ibid.*

42 *Ibid.*

43 The CAISO describes Category One transmission solutions as those that the transmission planning process will recommend to the CAISO Board for approval. *See Comments of the California Independent System Operator Corporation on Advanced Notice of Proposed Rulemaking,* FERC Docket No. RM21-17-000 (Oct. 12, 2021) at 26-27: https://www.caiso.com/Documents/Oct12-2021-Comments-AdvanceNoticeOfProposedRulemaking-BuildingTransmissionSystemoftheFuture-RM21-17.pdf.

44 *Id.* at 26.

planning under uncertain scenarios. The Commission should use the sensitivities to both inform future base cases *and* identify transmission solutions that would result in robust, multi-benefit upgrades beneficial under various outcomes. When transmission solutions that can provide multiple benefits are identified through the sensitivity analysis (*e.g.,* reliability *and* policy benefits, or load interconnections *and* generation interconnections), the Commission should request that CAISO consider taking those mitigations to the CAISO Board of Governors for approval for investment. Transmission is an expensive and time-intensive investment. Building a set of portfolios that are both low cost and low risk in the long-term will improve the robustness of California's grid planning and support reliability and clean energy objectives.

2. Comment on the modeling assumption updates made for this round of TPP recommendations. Are there other critical assumptions that you recommend? Be as specific as possible about assumptions and data sources.

CalCCA has no comments at this time.

3. Do you support the recommended Base Case for the 2026- 2027 TPP? Provide rationale for your recommendation. If you prefer a different Base Case portfolio, describe it as specifically as possible.

The Commission should modify the recommended base and sensitivity cases considering the uncertainty over the amount of data center load that will materialize and the amount of wind resources that should be included in the portfolios. *First*, the Commission should modify the magnitude of data center load used to develop the base case. Both the base and sensitivity case portfolios recommended by the Commission use the 2024 IEPR Demand Forecast Planning Scenario, which assumes data center load increases from one TWh in 2024 to 30 TWh by 2040, making up eight percent of total managed load.[45] As described in Section II. above, the 2024 IEPR

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[45] *26-27 Transmission Planning Process RESOLVE Modeling Results* (Sept. 30, 2025), at 19: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-

Demand Forecast is based on, among other factors, uncertain demand for data centers. To minimize the risk for building transmission for load that does not materialize, the Commission should modify the base case to use a more conservative forecast of data center load, such as the Commission's Reduced Load sensitivity data center assumptions.[46] The Commission should use the Planning Scenario for the sensitivity case.

Second, the Commission should modify the amounts of wind in the base and sensitivity cases to reflect moderate wind adoption in the base case and high wind adoption in the sensitivity case. CalCCA remains supportive of exploring opportunities for cost-effective investment in in-state, offshore, and OOS wind. As stated in the Ruling, however, wind resources currently face several obstacles, including the ending of tax credits, tariffs, and recent federal policies delaying or cancelling projects sited on federal land or seeking federal permits.[47] Incorporating these challenges in the base case would better reflect market and procurement realities for LSEs.

A moderate wind base case should maintain the amount of in-state and OSW included in previous TPP portfolios to remain consistent with previous TPPs, wherein the CAISO already approved transmission upgrades to support development of these resources.[48] However, the Commission should limit OOS wind in the base case, given the CAISO has stated that it is challenged in meeting the OOS resource requirements in the Commission's portfolios and that there are "no known transmission projects that can integrate these resources apart from SWIP-

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plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2026-2027-tpp/ruling_26-27-tpp-results_updated_20251013.pdf.

[46] *Mid-Term Need Determination Analysis* (Sept. 30, 2025), at 36: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2025_09_need-determination-analysis.pdf.

[47] *See* Ruling, at 8-9.

[48] For example, the CAISO's TPP has already approved key transmission infrastructure to integrate OSW. The 2023-2024 Transmission Plan includes projects in transmission constrained areas, like a new Humboldt 500kV substation, a new HVDC line from Humboldt to Collinsville, and a new 500kV AC line from Humboldt to Fern Road.

North (Idaho), TWE (Wyoming), and Sunzia (New Mexico)."[49] Unlike in-state transmission build, OOS transmission requires mutual agreement and close coordination with other states, further complicating the ability to access OOS resources. Therefore, the Commission should limit OOS wind in the base case to the amount in the sensitivity portfolio that reflects "the amount available to be delivered on existing transmission where the CAISO has rights."[50] The sensitivity portfolio can then include a higher wind scenario, including the full amount of OOS wind assumed in the Commission's proposed base case.

CalCCA's recommended modifications to the base case are intended to be least-regrets and reflect what resources realistically are expected to be available for procurement. The Commission should retain the ability to recommend the CAISO approve transmission upgrades beyond the base case so that proactive investments in transmission can be made when found to be low-risk and can offer multiple benefits. The Commission and CAISO can inform when to approve transmission upgrades found in the sensitivity analysis using: (1) information from LSEs, including CCAs, and data center customers that informs whether data center load is beginning to materialize consistent with the 2024 IEPR Planning Scenario; and (2) the CAISO's potential RFI to gather information and interest from developers in advancing beneficial transmission projects consistent with the OOS resource amounts in the Commission's portfolios.[51] The Commission should also request the CAISO to recommend upgrades identified in the sensitivity analysis if projects have multiple benefits (*e.g.,* policy/economic needs, or load/generation interconnection).

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[49] *2025-2026 Transmission Planning Process* (Sept. 24-25, 2025) at 36: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-2025-2026-TransmissionPlanningProcess-Sep2525.pdf.

[50] Ruling, at 17.

[51] *2025-2026 Transmission Planning Process* (Sept. 24-25, 2025) at 39: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-2025-2026-TransmissionPlanningProcess-Sep2525.pdf.

In summary, CalCCA recommends a moderate wind/data center adoption portfolio as the base case and a high wind/high data center adoption portfolio as the sensitivity case. The Commission should also request the CAISO to recommend upgrades identified in the sensitivity analysis dependent upon: (1) more up-to-date information on progress towards data center implementation milestones; (2) the results of the OOS wind RFI in CAISO 2025-2026 TPP; and (3) whether projects have multiple benefits (*e.g.,* policy/economic needs, or load/generation interconnection).

4. Do you support the proposed Limited Wind Sensitivity for analysis in the 2026-2027 TPP? Provide rationale for your recommendation. If you prefer a different Sensitivity portfolio, describe it as specifically as possible.

CalCCA recommends a modified sensitivity as described in response to question 3.

5. If you have a recommendation for a lower-overall-cost sensitivity portfolio to be evaluated, please describe it in detail.

The "lower-overall-cost" portfolio is dependent on assumptions made about resource availability and price, which may or may not reflect market realities. In particular, assumptions based on capital expenditure (CAPEX), levelized fixed costs, and levelized cost of energy may reflect the costs of building and operating generation. However, these assumptions may not incorporate scarcity pricing resulting from a constrained supply and demand balance. As shown in response to question 16 below, technologies other than solar and storage (*e.g.,* geothermal, wind) are currently very limited in the CAISO's interconnection queue. In addition, across the U.S., PPA prices for wind and solar have doubled over the last several years,[52] rising at rates beyond what might be expected from changes in capital costs.[53] Increased demand for new resources at a

[52] *See* LevelTen Energy: Q3 2025 PPA Price Index Executive Summary North America, available at https://www.leveltenenergy.com/ppa.

[53] SEIA analysis demonstrates flat trends in pricing of PV equipment: https://seia.org/research-resources/solar-market-insight-report-q2-2025/ (Section 5. National solar PV system pricing).

national scale may make the Commission's cost and availability assumptions optimistic if the supply of new resources is scarce. While LSEs will strive to procure their preferred resources that meet their reliability, clean energy, and energy cost hedging needs, the mix of those resources will change by necessity as the evolution of resource development, costs, availability, and federal incentives continue to shift.

6. How could the Commission address the very high solar build rates through 2031, observed in both the recommended Base Case and Sensitivity portfolios, driven by increased load forecasts from the 2024 IEPR and the 2030 GHG target? Do you have recommendations for alternative sensitivities that could achieve the near-term targets while mitigating risk and reducing potential costs to ratepayers? Provide rationale for your recommendations.

The Commission should recommend portfolios that most realistically reflect the future makeup of supply considering cost, risk, and feasibility. The Ruling's recommended base and sensitivity portfolios include considerable solar and storage resources. The Commission states that "[t]he buildout of solar, in particular, is so large that it calls into question whether it can feasibly be built in the quantities and timing identified in this round of IRP modeling."[54]

While the very high solar build rates in the portfolios warrant careful consideration to ensure they are scaled appropriately, potential alternatives to solar may not be able to support "near-term targets" in a lower risk and more cost-effective manner. As stated in response to question 3 above, OOS wind resources face numerous obstacles. As described in response to question 16 below, the CAISO's interconnection queue shows a limited supply of non-solar/storage resources available to procure. A feasible, cost-effective, and low-risk alternative is therefore unclear. The Commission should demonstrate the feasibility and cost estimates of any

[54] Ruling, at 12.

recommended alternative portfolio and, ultimately, recommend portfolios that reflect market and procurement realities for LSEs.

7. Comment on the busbar mapping methodology updates made for this round of TPP recommendations. Are there other critical updates that you recommend? Be as specific as possible about assumptions and data sources.

See response to question 9, below.

8. What criteria should the Commission adopt to inform mapping of EGS in California? Be as specific as possible about recommended assumptions and data sources.

CalCCA has no comments at this time.

9. Do you have recommendations for additional data sources to inform future updates to the commercial interest criteria, to supplement review of interconnection queue data? Be as specific as possible about assumptions, data sources, and application to busbar mapping.

The Commission should work with the CAISO to consider refinements to the commercial interest criteria necessitated by the new interconnection application intake process established in the CAISO's IPE 2023. The new interconnection intake process only accepts interconnection requests for projects located where there is already planned or existing transmission plan deliverability (TPD). The Commission's busbar mapping process relies primarily on the CAISO's interconnection queue to identify points of interconnection (POI) with commercial interest. If a POI has zero TPD available, projects will not be able to enter the interconnection queue at that POI, unless and until TPD is added through new projects triggered in the TPP. TPP projects are triggered based on where resources are mapped through the busbar mapping process.

These interactions have the potential to create a circular feedback loop that results in excess interconnection requests and infrastructure build out in areas with existing or planned TPD, and ignoring other areas, such as transmission-constrained local areas, where projects might be feasible, but no TPD exists. This could be especially problematic for location-constrained

resources, like geothermal, wind, or other technologies that can only interconnect at specific POIs. Therefore, the Commission and CAISO should consider how to identify areas with commercial interest outside of what is already in the interconnection queues. For example, a process could be created for developers to submit information on prospective projects, regardless of transmission availability, and their status before entering the interconnection queue.

IV. QUESTIONS RELATED TO THE PROCUREMENT NEED ANALYSIS AND RECOMMENDATIONS

10. Is another procurement order needed, as recommended in this ruling? What amount of resources (in ELCC MW NQC) should be required and for which years/tranches?

As a preliminary matter, ad hoc procurement orders such as the order being considered are not the most effective mechanism for bringing new resources online for several reasons. A *need for procurement* is not synonymous with a need for a *procurement order*. As discussed in Section I. above, CCAs in aggregate have been procuring above and beyond their MTR procurement requirements to serve their customer load and meet internal policies set by their boards. They remain committed to doing so absent a Commission directive via procurement order. In addition, ad-hoc procurement orders serve as policy shocks that interfere with LSEs' ongoing procurement efforts by unnecessarily shifting market power to developers. This leads to increased costs for LSEs and ultimately ratepayers, contributing to a growing affordability crisis. Finally, clean energy development is currently facing significant barriers outside of the control of LSEs conducting procurement, including supply chain delays, interconnection bottlenecks, permitting delays, and import tariffs. The impact to ongoing LSE procurement efforts of recent federal policy changes, including the cost impacts to ratepayers, will only be exacerbated by a procurement order at this

time.[55] The Commission should continue to prioritize the development and implementation of RCPPP and a programmatic framework so that procurement needs are identified far in advance on a regular cadence to allow for orderly procurement, avoid market disruption, and reduce ratepayer impacts.

Notwithstanding this objection to ad-hoc procurement orders, the answer to the question of whether a near-term ad-hoc procurement order is presently needed, and the amount and timing of resources needed, is also dependent on several factors as detailed below. In its consideration of a procurement order, the Commission must proceed cautiously due to forecasting uncertainties, to avoid over-procurement and related affordability implications for ratepayers. The Commission should also consider CalCCA's needs assessment which to some extent aligns with the Commission's procurement needs analysis *under certain inputs and assumptions,* as set forth in response to question 11 below.

Considering these factors, CalCCA recommends a two-tranche approach for a procurement order for 2029-2032: (1) Tranche One - 2,000 MW for 2029-2030; (2) Tranche Two - 2,000 MW for 2031-2032, and a needs analysis conducted in Q1 2027 regarding the additional 2,000 MW for 2031-2032 for a potential needs determination and procurement order in Q1 2028.

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[55] Federal policy developments are materially affecting MTR-eligible resource development. New "Beginning of Construction" requirements may undermine project eligibility for the Investment Tax Credit and Production Tax Credit, reducing the economic viability of certain projects. *See* United States Internal Revenue Service, Notice 2025-42, *Beginning of Construction Requirements for Purposes of the Termination of Clean Electricity Production Credits and Clean Electricity Investment Credits for Applicable Wind and Solar Facilities* (Aug. 15, 2025): https://www.irs.gov/irb/2025-36_IRB#NOT-2025-42). In addition, increased Department of Interior oversight may effectively preclude the development of wind and solar projects that interact with federal land. *See* U.S. Department of the Interior, *Departmental Review Procedures for Decisions, Actions, Consultations, and Other Undertakings Related to Wind and Solar Energy Facilities* (July 15, 2025), at 1: https://www.doi.gov/media/document/departmental-review-procedures-decisions-actions-consultations-and-other.)

First, if the Commission determines the need to issue a procurement order pending the implementation of programmatic procurement through RCPPP, it should proceed cautiously in light of the uncertainty baked into the 2024 IEPR Demand Forecast utilized as the basis for the Commission's needs analysis through 2032. As discussed in Section II. above, given doubts raised by regulators, the IOUs, and stakeholders regarding data center load materializing, the Commission should carefully consider the magnitude of the procurement order. In addition, changes in Federal EV policies and incentives may result in a 32 percent reduction in EV adoption than assumed in the forecast.[56] CalCCA's analysis, described in detail in response to question 11 below, finds a 5,671 MW need in 2032 under the CEC 2024 IEPR Planning Scenario. Incorporating the impacts of less data center growth and changes in EV demand, the CalCCA analysis shows a 1,932 MW need in 2032 under a Low Demand Growth sensitivity. Therefore, the 6,000 MW of capacity identified in the Ruling *may* be needed, but *only if the load growth in the 2024 IEPR Planning Scenario materializes*.

Second, if the Commission moves forward with the procurement order, CalCCA recommends that the Commission first order procurement of 2,000 MW for an initial 2029-2030 tranche, rather than the Ruling's proposed 1,500 MW in 2029 and 1,500 MW in 2030. The 2,000 MW tranche through 2030 would result in procurement over the Commission's "reduced load" sensitivity (requiring 1,347 MW), but less than the 3,000 MW identified with the Base or Delayed LLT portfolios which incorporate the 2024 IEPR Demand Forecast's Planning Scenario and its attendant uncertainties concerning large loads and electrification. CalCCA also recommends the Commission initially order procurement of 2,000 MW for the second tranche (2031-2032),

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[56] Trump EV Policy.

consistent with the Commission's data center load assumptions in its reduced load sensitivity.[57] The Commission should re-evaluate in 2027 the need for the additional procurement to occur in the second tranche, with an official need determination in Q1 2028,[58] after the CEC's IEPR Demand Forecast's assumptions about large loads and electrification are further scrutinized and there is more confidence these loads will materialize.[59]

As described more fully in response to question 12 below, this phased approach will avoid prescriptive procurement requirements for each year that can restrict LSEs in a manner that will produce higher costs. Strict compliance dates, like the ones established for the MTR requirements, are overly precise for the realities of project development, especially given that a variety of factors outside the control of LSEs or developers (*e.g.,* supply chain, transmission/interconnection delays, siting, and permitting) can cause resource delays. Alternatively, compliance that is assessed in tranches better ensures reliability needs are met cost-effectively by allowing LSEs to evaluate offers from a potentially larger pool of projects with varying CODs within the tranche and to manage short project delays without facing non-compliance. For this reason, the Commission should establish two procurement tranches, one for 2029 and 2030 and the second for 2031 and 2032. In summary, if a procurement order is issued, the Commission should adopt the requirements and process for Tranche Two re-evaluation of need in **Table 1**.

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[57] *Mid-Term Need Determination Analysis* (Sept. 30, 2025), at 36: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2025_09_need-determination-analysis.pdf.

[58] If RCPPP can be implemented in advance of the reassessment of the second tranche need, the RCPPP requirements should supersede the procurement order requirements as stated in response to question 24.

[59] Phasing in of the procurement order requirements would function similar to the multi-year local RA requirements, in which procuring entities procure 100 percent of the immediate two years' needs and only a portion of the three-year out need.

Table 1: CalCCA's Proposed Procurement Tranches

	Tranche	Cumulative Procurement (Net Qualifying Capacity (NQC) MW)	Incremental Procurement (NQC MW)
2029-2032 Procurement Order Issued by Q1 2026			
Initial Need Determination	Tranche 1 (2029-2030)	2,000	2,000
	Tranche 2 (2031-2032)	4,000	2,000
2031-2032 Procurement Order, if deemed necessary, issued by Q1 2028[60]			
Incremental Need Determination	Tranche 2 (2031-2032)	TBD (Between 4,000-6,000)	TBD (Between 0-2,000)

11. Should the Commission base a potential procurement order on an alternative study or rationale beyond that described in this ruling? If so, provide the study and explain why it should be used instead.

As stated in response to question 10, CalCCA recommends the Commission avoid ad hoc procurement orders given they are not the most effective mechanism to ensure reliability. If the Commission moves forward, however, it should do so in a manner that recognizes the significant uncertainty in the current IEPR Demand Forecast and allows for reassessing and reallocating needs in later years if the forecast changes or does not materialize as expected. CalCCA performed an analysis of the 2030 and 2032 supply and demand balance under a range of future scenarios exploring the uncertainty in data center, EV and Additional Achievable Fuel Switching (AAFS) load growth as shown in **Figure 2**. Inputs and assumptions for CalCCA's study are provided in Appendix A, attached hereto.

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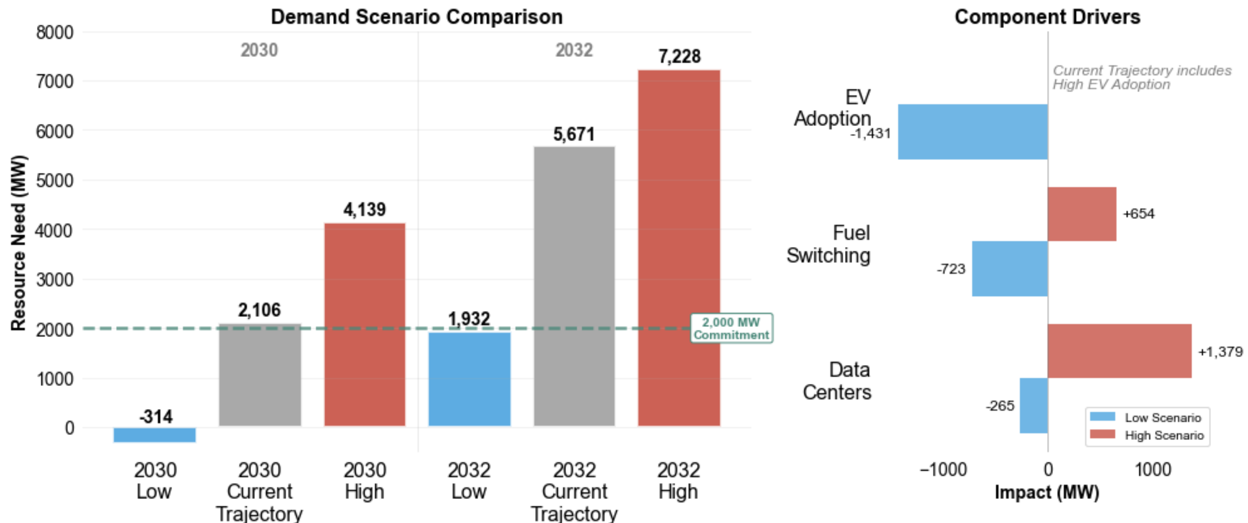
60 If RCPPP can be implemented in advance of the reassessment of the second tranche need, the RCPPP requirements should supersede the procurement order requirements as stated in response to question 24.

Figure 2: CalCCA Study - Demand Scenario Comparison and Component Drivers



CalCCA's analysis, as set forth in **Table 2** below, finds a 2,000 MW procurement need for Tranche One (2029-2030), and aligns with the current trajectory of load growth *if* the 2024 IEPR Planning Scenario materializes (see **Table 2**, Row 1).[61] Because procurement activity for Tranche One will need to commence quickly after a procurement order is issued, setting the procurement requirement based on the 2024 IEPR Planning Scenario is therefore a reasonable starting point.

Given the significant uncertainty in the current IEPR Demand Forecast, however, the Commission should refrain from setting the procurement requirement at 100 percent for Tranche Two. Projected shortfalls in 2032 range from 1,932 MW to 7,228 MW between the low and high demand growth assumptions in CalCCA's study (see **Table 2**, Rows 4-6). If the Commission requires LSEs to procure to the full 6,000 MW requirement in Tranche Two without an interim reassessment of demand growth assumptions, LSEs could be over 4,000 MW over-procured. The Commission should therefore set the procurement requirement for Tranche Two initially at 50

[61] As stated in Appendix A, CalCCA's analysis excludes Diablo Canyon Power Plant (DCPP) capacity, recognizing that SB 846 requires the Commission to use DCPP's original retirement dates of 2024 and 2025 for planning purposes. CalCCA performed a sensitivity of 2030 reliability needs with DCPP retained and identified small net surplus (~174 MW) under the CEC 2024 IEPR Planning scenario.

percent, consistent with the Commission's data center load assumptions in its reduced load sensitivity.[62] By Q1 2028, the Commission can re-evaluate the need for the additional 2,000 MW of procurement to occur in Tranche Two, as described in response to question 10.

Table 2: CalCCA Study - Demand Scenarios and Minimum Net Supply

	Year	**Scenario**	**Load Forecast**	**Description**	**Minimum Net Supply (MW)**
1.	2030	Current Trajectory	CEC 2024 IEPR Planning	Medium Case Data Center Growth (2331 MW), Fuel Switching- AAFS Scenario 3 from IEPR 2024, High Estimate of EV Growth	-2,106
2.	2030	High Demand Growth	2024 IEPR with High Data Center, High EV, High AAFS	Combination of 3532 MW Data Center, AAFS Scenario 4 from IEPR 2024, High EV	-4,139
3.	2030	Low Demand Growth	2024 IEPR with Low Data Center, Low EV, Low AAFS	Combination of 2100 MW Data Center, AAFS Scenario 2 from IEPR 2024, Low EV (32% reduction)	314
4.	2032	Current Trajectory	CEC 2024 IEPR Planning	Medium Case Data Center Growth (2904 MW), Fuel Switching- AAFS Scenario 3 from IEPR 2024, High Estimate of EV Growth	-5,671
5.	2032	High Data Center	CEC 2024 IEPR Planning with High Data Center	Data Center Load 4261 MW (CEC high end estimate)	-7,228
6.	2032	Low Demand Growth	2024 IEPR with Low Data Center, Low EV, Low AAFS	Combination of 2250 MW Data Center, AAFS Scenario 2 from IEPR 2024, Low EV (32% reduction)	-1,932

[62] *Mid-Term Need Determination Analysis* (Sept. 30, 2025), at 36: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2025_09_need-determination-analysis.pdf.

12. Comment on the impact a Commission procurement order could have on the market for the necessary resources. Provide evidence of your assertions, if possible.

An ad hoc procurement order could introduce seller market power and add market volatility such that sellers will use compliance obligations as an opportunity to maximize their profits. While CalCCA appreciates the Commission's needs assessment used to inform its proposed procurement order, the final amount of the reliability need is uncertain at this time due to the nature of the anticipated load growth, as detailed in Section II. above. LSEs are already procuring new resources to meet other needs, including compliance with the RPS program and previous MTR orders. A procurement order sends a message to an already tight market that will impact the cost at which procurement will occur.

Developers use many market signals to assess market demand. A procurement order can give a very strong signal of significant demand, resulting in higher prices for necessary resources, especially when supply is constrained by multiple factors as outlined in response to question 16. Additionally, LSEs may be forced to contract with projects that have not already been contracted with because they may not meet an LSE's reliability need or be cost-effective. As discussed below, should the Commission pursue a procurement order the Commission should set rules to ensure a competitive market, including: (1) allowing flexible compliance methods; (2) taking measures to ensure that LSE allocations under a new procurement order do not reveal an LSE's net position to potential sellers; and (3) only issuing a procurement order based on need, rather than an order encouraging unbounded procurement to take advantage of expiring tax credits which may result in overly high demand and potential market power.

First, the Commission should allow flexible compliance methods. Prescriptive procurement can restrict LSEs in a manner that will produce higher costs and be misaligned with procurement realities. Resource-specific or even attribute-based procurement (*e.g.,* orders for long-lead time

(LLT) resources) can box in an LSE, causing their procurement to be unnecessarily constrained and costly. Instead, LSEs should be allowed to procure resources based on their contribution toward meeting the requirement (*i.e.,* their NQC). Additionally, as discussed in response to question 10 above, the Commission must be aware of the impacts of strict compliance dates. This is particularly true in the current environment, where a variety of factors outside of the control of LSEs cause resource delays. CCAs have generally found that procurement assessed in windows or tranches rather than annual requirements, like those of RPS, is preferable. This flexibility allows for the inevitable complications that arise when procuring new generating resources. Evidence of the impact of procurement orders can be found in D.25-09-007, specifically regarding the requirement to bridge MTR needs and the "considerable costs" of doing so. D.25-09-007 recognizes that bridging requirements place unnecessary costs on LSEs already meeting resource adequacy (RA) needs.

For this reason, the Commission should establish two procurement tranches, as described in response to question 10. Allowing LSEs more flexibility in the timing of procurement enables them to optimize procurement and minimize costs. Given the uncertainty of load growth, having latitude in procurement allows for cost-effective procurement. In addition, any procurement order resulting from the Ruling should explicitly carry forward D.25-09-007's flexible compliance alternatives to ensure reliability is met cost-effectively.

Second, the Commission must take measures to ensure that LSE allocations under a new procurement order do not reveal an LSE's net position to potential sellers. While the order does set a total need, the Commission will set the baseline as an assumption that prior MTR orders have been met. By doing so, entities that have gone above and beyond their need will have a lower, and possibly zero, net position. This helps prevent the market from knowing too much about the needs

of any individual entity. However, if the Commission provides public information about LSE-specific compliance with MTR orders, this mitigation will be lost as the market will have information that can be used to identify an individual party's need. Failure to protect the confidentiality of LSEs' net positions could potentially create opportunities for market sellers to exercise market power and ultimately exacerbate the affordability crisis.

The Commission should therefore publicly report only aggregate information on compliance with prior MTR orders, avoiding disclosure of the net position of any individual entity until the proposed interim order is complete. This is consistent with the reporting that the Commission has provided in progress reports on MTR procurement progress.[63] The Commission also should refrain from publishing non-compliance information about specific LSEs publicly until the interim procurement order contemplated is complete (*i.e.,* after 2032).

Third, the contemplated procurement order is far superior to an order that would have LSEs or a subset of LSEs embarking on a mission to procure *all resources* eligible for tax credits, as requested by the ACP-CA Motion. Such an unbounded order would define the need for the procuring entity at a level that could be anticipated to be subject to the potential exercise of market power and produce an outcome far in excess of need. For this reason, the Commission should limit its procurement order to ensure the procurement and development of resources eligible for tax credits, but refrain from an unbounded order such as the one requested by ACP-CA that may result in overly high demand and potential seller market power.

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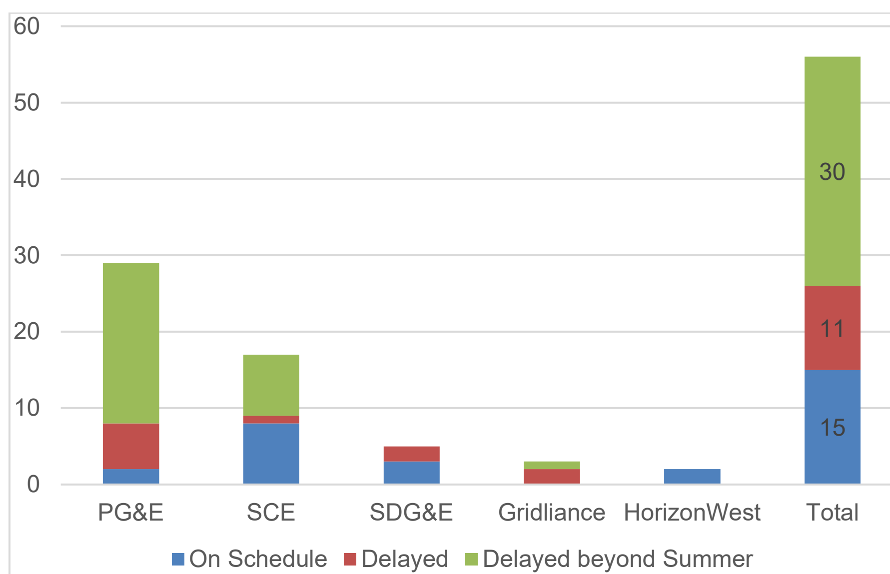
[63] *See* https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track.

13. In addition to or instead of procurement proposed in this ruling, are there other measures outside of the IRP context that the Commission should consider? If so, explain your recommendations in detail.

Yes. Several barriers outside the procurement process are causing difficulties in the timely development and procurement of new resources. Challenges with permitting, siting, and licensing, as well as transmission and interconnection delays, have resulted in delays in resources reaching commercial operation. For example, during the CAISO's July 30, 2025, Transmission Development Forum, participating transmission owners indicated that 41 out of 56 approved transmission projects face delays, as shown in **Figure 3** below.

Figure 3: Status of Approved Transmission Projects as of the July 30, 2025, Transmission Development Forum[64]



The Commission can issue procurement orders and LSEs can procure to them, but until the barriers are addressed, it will continue to be difficult for procured projects to meet COD on schedule. The Commission, as a participant in the Tracking Energy Development (TED) task force, is uniquely positioned to ensure that concerns about potential project delays are addressed

[64] *See* https://www.caiso.com/meetings-events/topics/transmission-development-forum.

expeditiously. Given the importance of meeting the generation needs and the potential for LSE penalties for failures to procure on schedule, the Commission via the TED task force should work to ensure that procured resources can achieve their COD.

14. If the Commission orders procurement in the IRP proceeding between 2028-2032, should it be for generic capacity, or should there also be an energy component (due, in part, to the declining ELCCs of battery storage)? Why or why not? Do the resource adequacy Slice of Day requirements adequately address this issue? Why or why not?

Any procurement order resulting from the Ruling should be for generic capacity only. Since the RA slice-of-day (SOD) program looks at all 24 hours of the worst expected day in each month, it has effectively addressed energy needs in addition to capacity needs. In fact, the program accounts for excess capacity needed to charge an LSE's shown storage. Since LSEs optimize their procurement across both IRP and RA obligations and LSEs ultimately must meet a SOD requirement for RA, LSEs will have to consider how their IRP procurement affects their SOD position. As recommended in CalCCA's comments on the RCPPP,[65] the Commission should therefore align requirements in the IRP program with those in the RA program, setting procurement obligations consistent with SOD, rather than ELCC.

For example, SOD has counting rules for each type of technology. For renewable resources, SOD uses an exceedance-based measure of the average generation profile for similarly situated resources. Battery storage is treated using a method that accounts for excess capacity from generating resources in some hours to charge the battery, including efficiency losses. While this process is necessary for RA, it is not necessary for a procurement order. The

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65 *See,* R.20-05-003, *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, (July 15, 2025), at 12-14: https://cal-cca.org/wp-content/uploads/2025/07/Comments-on-ALJs-Ruling-Seeking-Comments-on-Reliable-and-Clean-Power-Procurement-Program-from-Staff-Proposal-07-15-25.pdf.

procuring LSE will also need to meet annual and monthly RA obligations and thus has a strong disincentive to over-procure storage to meet an IRP procurement order, knowing that without sufficient generation, they will be unable to charge storage to meet RA counting obligations. In D.22-06-050,[66] the Commission stated that the 24-hour framework directly addresses energy sufficiency at an individual LSE level by requiring each LSE to provide sufficient excess energy to charge any storage it shows across the 24-hour slices. Given that the RA SOD framework is designed to account for energy storage charging needs, and LSEs are incentivized to co-optimize their IRP procurement with its RA procurement, it is unnecessary for an IRP procurement order to address this issue.

Finally, any interim order must not be considered in isolation. LSEs are already subject to RPS requirements based on the amount of energy produced by renewable generation to serve load. Furthermore, RA requirements ensure LSEs procure sufficient capacity in advance to meet forecasted load for each hour of the day. The combination of these two compliance obligations means LSEs are already procuring to meet energy needs, and incentivized to procure both energy and capacity in a least cost manner that fits their customers' load shape. For these reasons, the Commission should structure any procurement order for generic capacity only, using SOD counting rules.

15. If energy resources are needed for 2028-2032, should the RPS program be used for procurement of additional energy resources, rather than ordering procurement in the IRP context? Provide your rationale.

No. The Commission should not use the RPS program to order procurement. The needs assessment advanced in the Ruling focuses on reliability needs rather than clean energy needs, the

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[66] D.22-06-050, *Decision Adopting Local Capacity Obligations for 2023 - 2025, Flexible Capacity Obligations for 2023, and Reform Track Framework*, R.21-10-002 (June 23, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF.

focus of the RPS program. To the extent an LSE needs to procure additional clean energy to achieve RPS compliance, the Commission can presume that the LSE will seek to satisfy its RPS need *and* interim procurement order needs by procuring a new clean energy resource that satisfies both requirements. There is therefore no need to place an entity under double jeopardy by issuing multiple penalties for the same deficiency. That is, new capacity needs (*i.e.,* an interim procurement order) should be based on the reliability needs of the grid, while renewable energy needs should continue to be evaluated through RPS. Placing both capacity and renewable energy needs within an interim order will place LSEs at risk three times: once for failing to meet the capacity need that the interim order was targeting, a second time for not meeting the renewable energy amounts if included in the interim order, and a third time through RPS compliance for missing the same renewable energy need.

Finally, the Commission should strive to enable LSEs to procure in a manner consistent with their own portfolio needs. In the Ruling, the Commission attempts to address this issue through a baseline that acknowledges that LSEs may have already contracted beyond the MTR orders and should not be required to procure above and beyond the total need of both orders. Given that the Commission has not requested data on RPS needs for the 2028-2032 period, the likely result would be a pro-rata allocation of renewable energy requirements, which is unlikely to align with the needs of any LSE individually.

16. Comment on the LLT resource delay assumptions of three years. What challenges are present in procuring these resources and bringing them online?

There is limited supply of LLT resources available to procure. Those that are available are costly and/or face interconnection delays, making them more difficult to procure. Limited supply availability will continue to be a challenge, as the CAISO's interconnection queue for active projects includes very little LLT capacity, as shown in **Figure 4** below.

Figure 4: CAISO Interconnection Queue Technologies by Cluster with Proposed Online Dates Between 2029 and 2032[67]

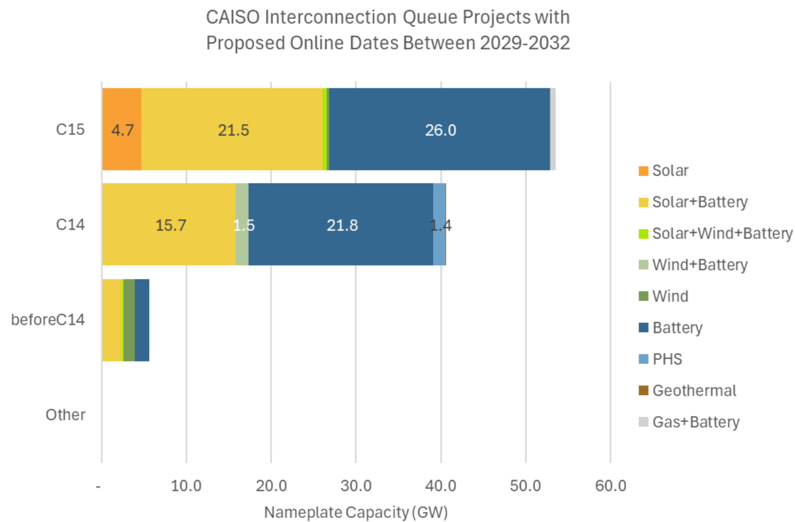

Figure 4 demonstrates that there is very little resource diversity in the queue for resources with proposed online dates within the procurement order window of 2029 through 2032. Technology-specific elements of any order exacerbate market distorting effects by pushing LSEs to pursue projects from an even smaller subset of developers. This would make the market power concerns especially acute for the selected technology type. The Commission should therefore only order procurement of generic capacity and refrain from adopting an LLT-specific procurement order. This will ensure LSEs have the flexibility to procure resources that are available and cost-effective and are not forced to procure technologies with limited availability, and therefore limited competition among suppliers and high prices.

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[67] *Data from Berkeley Lab's Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection 2025 Data File* (https://emp.lbl.gov/sites/default/files/2025-08/LBNL_Ix_Queue_Data_File_thru2024_v2.xlsx).

17. Should a procurement order, if one is issued, specify particular characteristics for resource procurement (e.g., clean firm, long-duration storage, etc.), or should the requirement be entirely for generic capacity resources?

As explained in response to questions 14 and 16 above, if a procurement order is issued, the Commission should order procurement of generic capacity only. Technology-agnostic procurement orders mitigate market power by contemplating a larger pool of eligible resources and allow LSEs to meet reliability needs while keeping costs low. Procurement orders that require particular resource characteristics can result in costly procurement, especially if the technologies that can provide those characteristics are scarce. Clean firm resources and long-duration storage may not currently be in the CAISO queue in sufficient volumes to allow for competitive market conditions. In addition, the RA program, through SOD, will drive the procurement of attributes needed to ensure sufficient capacity in all hours of the day. For these reasons, if a procurement order is issued, the Commission should order procurement of generic capacity only.

In addition, the Commission should not specify procurement of long-duration storage because the RA proceeding is currently undergoing a process for establishing long-duration storage accounting methodology.[68] Until that proceeding is resolved and there is clarity on how these resources count for RA, the Commission should refrain from ordering procurement of long-duration storage.

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68 D.25-06-048, *Decision Adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinements*, R.23-10-011, at 66: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K237/571237404.PDF.

18. Should a procurement order, if one is issued, consider relaxing any of the resource eligibility requirements associated with prior MTR orders? If so, what should be changed? Explain your rationale.

Resource eligibility should be consistent with prior MTR orders for generic capacity. This includes eligibility for imports that will be delivered through maximum import capability (MIC).[69]

The Ruling asks parties to comment specifically on whether repowers should be eligible to count towards procurement requirements given "there are resources that will enter retirement age in the late 2020s and early 2030s."[70] The Commission's needs assessment assumes these aging resources remain online, which means they are potentially included in the baseline resource list past their actual useful life. In practice the goal of the IRP procurement track should not be to set a target *incremental* capacity, but rather the required *total* capacity to retain system reliability, as CalCCA has recommended for RCPPP.[71] For this reason, there is no functional difference between retaining a MW of NQC in the baseline through a repower that otherwise would have retired versus that resource retiring and being replaced with new incremental capacity. In practice however, the latter could be a slower and more costly option.

The Commission should therefore allow repowers to count toward procurement requirements as incremental capacity for the purposes of this order and consider adjustments to the need determination in the second needs assessment CalCCA recommends for Tranche Two in

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[69] The Commission should allow new resources to count without MIC so long as LSEs are making good faith efforts to obtain it, as it has with the MTR Order. Currently, the CAISO only allocates long-term MIC for RA contracts active in the next RA year. Until the CAISO process for allocating long-term MIC changes, LSEs signing long-term PPAs for resources with online dates more than one year in advance will be unable to secure MIC for those resources until the year before the resources come online. The CAISO's RA Modeling and Program Design initiative will reconsider the methodology for allocating long-term MIC.

[70] *See* Ruling, at 36-37.

[71] *See* R.20-05-003, *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal* (July 15, 2025), at 10-11: https://cal-cca.org/wp-content/uploads/2025/07/Comments-on-ALJs-Ruling-Seeking-Comments-on-Reliable-and-Clean-Power-Procurement-Program-from-Staff-Proposal-07-15-25.pdf.

2027. Ideally, any additional procurement will be conducted under a new RCPPP framework, which CalCCA expects to more holistically address repowering issues.

If, however, the Commission believes repowers must result in capacity incremental to the baseline for a procurement order resulting from this Ruling, the Commission should allow repowers of baseline capacity to be treated as a "baseline swap." This would allow LSEs to request removal of the repower capacity from the baseline to qualify for Tranche One procurement requirements, and result in the Commission adding a corresponding amount of NQC to the LSE's Tranche Two requirements. If the repowering results in a greater NQC than assumed in the baseline, the LSE should be allowed to count any new NQC as incremental capacity for the purposes of its IRP procurement compliance.

It is important from a reliability perspective that the Commission's procurement framework incentivize repowers when they are cost-effective. The issue of how to account for repowers in procurement orders highlights the challenges of relying on a baseline. This is because if resources choose to retire because the procurement framework does not incentivize repowers, then a new reliability need is created beyond the need identified when the baseline was established. The Commission should therefore seek to develop an RCPPP based on a total need, counting LSE procurement of both new and existing resources to ensure the clear treatment of repowers and provide resources with the incentives to repower when it is cost-effective.

19. If a procurement order is issued, comment on how the need determination should be allocated to LSEs.

If a procurement order is issued, the Commission should allocate the procurement requirements using the most recently available peak load ratio share for each tranche, using the MTR baseline and allowing LSEs to count excess MTR and Supplemental MTR procurement

towards the new procurement order and RCPPP. This methodology should be an interim allocation methodology until a total needs-based methodology can be developed and implemented for RCPPP.

Ultimately, the Commission should seek to urgently develop and transition to a total needs-based allocation in RCPPP that fully accounts for LSEs' past procurement of new and existing resources. Baselines are fundamentally problematic as they do not fully account for LSEs' past procurement and how that procurement covers their total needs. As described in response to question 23, failing to account for past procurement can disincentivize early procurement done outside of procurement orders and penalize early actors. Baselines are also complex to develop and difficult to maintain. The Commission should therefore urgently focus its efforts on developing a total need-based allocation methodology for use in the RCPPP.

20. Given efficiencies associated with procuring at scale, should the Commission consider ordering central procurement of resources, if additional procurement is ordered? Why or why not?

The Commission should not order central procurement of resources. If additional procurement is ordered, the Ruling's recommendation to allocate procurement requirements to all LSEs is the right approach for several reasons. *First*, it is not clear that central procurement results in efficiencies. In the RA context, central procurement of local RA has resulted in CPE procurement shortfalls and increased uncertainty for LSEs procuring their own system and flexible RA requirements. Central procurement of the effective PRM has added demand to the market at the same time LSEs are procuring to meet their own internal obligations and, when supply is scarce, that demand can put upward pressure on RA prices. Similarly, central procurement in IRP drives up demand for resources and therefore potentially drive costs up as the competition for scarce supply increases. The Commission should not order central procurement based on supposed efficiencies that have not been demonstrated.

Second, LSEs have demonstrated the ability to successfully meet their own procurement requirements. CCA procurement has collectively far exceeded aggregate CCA MTR requirements, as shown in **Figure 1**, above. When there are efficiencies to procuring at scale, LSEs have demonstrated the ability to realize these efficiencies through joint procurement efforts.[72]

Third, allocating procurement requirements to all LSEs adheres to the statute enabling CCA procurement autonomy. Public Utilities Code section 366.2(a)(5) requires a CCA to be "solely responsible for all generation procurement activities on behalf of the [CCA's] customers, except where other generation procurement arrangements are expressly authorized by statute." Central procurement of the capacity in this order has not been justified or expressly authorized in statute.

Fourth, central procurement makes it difficult for LSEs to optimize their own portfolios because they do not know the amount or attributes of the central procurement and whether there is room in their existing portfolios for those resources.

While the Ruling states that there are other approaches beyond LSE-based procurement that could be considered, such as allocating need to the IOUs to procure on behalf of all LSEs or adjusting the effective PRM,[73] these approaches have serious drawbacks and should not be considered. IOU central procurement and the effective PRM create an uneven playing field across LSEs by allowing the IOUs to shift resources to and from their bundled portfolio and the portfolio paid for by all load. This gives the IOUs an unfair advantage relative to other LSEs by allowing the IOUs to place their most costly procurement in the portfolio paid for by all load.

The core function of LSEs is to procure for their customers' electricity needs. Reliance on centralized procurement by the IOUs undermines this function. It is also unclear, given the LSEs'

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72 For example, CC Power, a joint powers authority comprised of nine CCAs, contracted for a 50 MW/400-MWh LDES project: https://cacommunitypower.org/cc-power-members-approve-second-longduration-contract/.

73 *See* Ruling, at 37.

MTR procurement track record and the IOUs struggle to meet their effective PRM targets,[74] whether IOU central procurement would be more successful than procurement by all LSEs. Instead, the Commission should allocate any procurement order resulting from this Ruling to all LSEs to meet the needs of their customers.

21. If a procurement order is issued, should there be requirements for procurement within local capacity areas? If so, which ones, and how should this requirement be designed?

No. The Commission's needs assessment focuses on *system* reliability needs, not local reliability needs. In addition, local areas are transmission-constrained and often land-constrained, making siting and permitting of generation in those areas exceptionally challenging. Requiring specific local area procurement without consideration of transmission needs and land-use will likely drive-up costs and increase risk of non-compliance. Instead, as recommended in CalCCA's comments to the OIR in this proceeding, the Commission should prioritize the development of a comprehensive framework for determining how to reliably serve local area load in the most cost-effective manner, considering the feasibility and cost of transmission and generation alternatives.[75]

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[74] *California Public Utilities Commission (CPUC) Staff Review of Load-Serving Entities' (LSEs') Compliance with the Mid-Term Reliability (MTR, D.21-06-035) and Supplemental MTR (SMTR, D.23-02-040) Decisions* (July 2025): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/compliance-status-reportmid-term-reliability-mtr-and-supplemental-mtr.pdf; and *Workshop on Track 3 Proposals in R.23-10-011, R.23-10-011* (Feb. 12, 2025), at 51: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/r23-10-011/ra-track-3-workshop-feb-12.pdf.

[75] R.25-06-019, *California Community Choice Association's Comments on the Order Instituting Rulemaking* (Aug. 5, 2025), at 15-16: https://cal-cca.org/wp-content/uploads/2025/08/Comments-on-the-OIR-to-Continue-Oversight-of-EIRP-08-01-25.pdf.

22. Should capacity accreditation be based on forthcoming incremental ELCC analysis? If you prefer another method for resource accreditation (such as extension of existing accreditation, straight-line decline, or less frequent updates to values), describe it in detail. Also describe how resources should be submitted and processed for compliance review.

As described in response to question 14, the Commission should not rely on ELCC as the accreditation methodology, as it is not consistent with the RA reliability measure, which uses SOD. The Commission should avoid using different measures for reliability needs as it runs the potential of forcing entities to comply with the more stringent of two requirements when either would provide a reliable outcome.

Using SOD accounting for an interim procurement order would not require evaluating all 24 hours. Rather, the Commission should use the results of its LOLE modeling to identify the months and hours with LOLE events driving the reliability need and count each resource using its SOD accounting in those hours. The Commission should then look at the value of the procured resources in each of these hours to determine if each hour meets the minimum procurement requirement for the LSE. For example, if the Commission's LOLE study produces two LOLE hours, each LSE will submit their procured resources and provide the SOD accounting for both hours. The procured resources will need to meet or exceed the required quantity for each hour. If it is not possible to implement a SOD measure for this interim procurement order, the Commission should commit to its use in the RCPPP to better align compliance mechanisms.

If the Commission decides to use ELCC as the counting mechanism for this interim order, then the Commission must: (1) ensure that the ELCC accurately accounts for charging sufficiency for battery storage; (2) perform the ELCC calculations by tranche (see responses to questions 10 and 12) to accurately depict the value of the resource at the time it is required to reach commercial

operation; and (3) fix the ELCC values sufficiently far in advance of procurement to allow LSEs to optimize procurement.

First, ELCCs can change dramatically depending on the other resources on the grid. This is particularly true for storage as its ability to meet load needs is dependent on excess generation from other resources to enable its charging. With the large amounts of storage that have come online and with significant amounts still in the CAISO interconnection queue, determining the ELCC of incremental storage is very important in guiding LSE procurement.

Second, since ELCCs can change between each study of their value, the Commission should avoid annual updates to the ELCC values, which will significantly increase the difficulty in LSEs understanding their resource needs. This will complicate procurement and compliance, potentially leading to either non-compliance or costly over-procurement. To address this, the Commission should establish ELCCs for each tranche as recommended in response to question 10. Doing so will provide certainty to LSEs but also allow for the ELCCs to change based upon resources expected to be brought to the grid in the first tranche. The Commission should also re-assess the ELCC between the initial need determination and incremental need determination recommended by CalCCA to provide consistency and accuracy of the needs assessment and total procurement obligation between each tranche.

Third, the Commission should fix ELCC values prior to setting the compliance obligations to enable LSEs to complete contracting with new resources with sufficient certainty that their procurement will be compliant. It would be reasonable to fix the ELCC for Tranche One (2029 and 2030) by Q1 2026 and Tranche Two (2031 and 2032) by Q1 2028. This will balance the need to adjust ELCC to reflect impacts to reliability while allowing LSEs the certainty necessary to perform procurement.

23. Should the Commission continue to use the existing MTR compliance baseline and allow LSEs who have excess procurement relative to their MTR and Supplemental MTR obligations to count their excess procurement toward any new obligations? Why or why not?

Yes. As stated in response to question 19, the Commission should ultimately transition to a total needs-based allocation in RCPPP that fully accounts for LSEs' past procurement of new and existing resources. If the Commission orders procurement in the interim, it should use the existing MTR compliance baseline and allow LSEs to count their excess MTR and Supplemental MTR procurement towards their new obligations. Doing so will encourage LSEs to continue to be proactive in their procurement efforts. The Commission has routinely indicated that past procurement would be allowed to count towards future orders.[76] The Commission should not reverse this commitment – otherwise, LSEs may be punished for early actions if their procurement outside of procurement orders will not count towards future need allocations.

24. How should any potential new procurement order relate to a potential adoption of the RCPPP requirements?

Any interim procurement order should be designed to not conflict with the RCPPP. In addition, the RCPPP should account for any procurement performed in this interim procurement order and enable the LSE to use that procurement to meet any future RCPPP needs. Doing so will ensure the Commission does not penalize or disincentivize early actors, or drive over procurement either in total or on an individual LSE basis.

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[76] *See* Ruling, at 29 ("LSEs may be procuring (i.e., signing contracts) with resources in excess of requirements for a variety of reasons, including anticipation of resource development delays or failures, anticipation of resource adequacy requirements, assessment of resource value, anticipation of RPS requirements, or LSE-specific portfolio objectives. The Commission has several times indicated that LSEs that procure in excess of their MTR requirements should expect to be able to count incremental additional resources towards any future needs without regards to a baseline update, and this ruling proposes to continue that principle.") (citations omitted).

To accomplish these goals, the Commission should either set the RCPPP to become effective after this interim procurement order concludes or allow the RCPPP requirements to supersede the interim procurement orders. Either option must ensure that the rules set between the two programs do not disincentivize early action and do not result in costly over-procurement.

Overall, the Commission should continue to prioritize the development of the RCPPP with a goal that it, combined with SB 100, RA and RPS, will meet the reliability and clean energy needs without intervention from interim procurement orders.

25. What other actions should the Commission take, in conjunction with, or as a substitute for, a procurement order, to cost-efficiently promote system reliability and emissions reductions during the 2028-2032 period? Be as specific as possible.

The Commission should encourage all reasonable transactability to produce a compliant result. CalCCA anticipates that, *in aggregate,* the CCAs' current procurement shown to meet MTR needs are likely to meet a significant portion, if not all, of the need determination proposed in the Ruling, as demonstrated in **Figure 1,** above. However, the aggregate will not be true for all individual CCAs. Enabling meaningful transactability by allowing LSEs to trade obligations, without requiring the bi-directional trade required for the MTR and Supplemental MTR orders,[77] will allow cost-effective compliance. For example, an LSE that is long in 2029 could trade an obligation with an LSE that is short in 2029. This obligation trade will then have the second LSE taking on additional compliance in a future year when the first LSE is planning to use the resource for its own compliance need or could be met by one or each LSE procuring more in a future

[77] In D.23-02-040 at 89, Ordering Paragraph (OP) 10, the Commission approved a framework for the trading of compliance obligations between two LSEs. Specifically, the Decision provides that: "Any two load serving entities (LSEs) with compliance obligations under Decision (D.) 19-11-016, D.21-06-035, and/or this order may trade compliance obligations in arrangements that may include financial remuneration, but may not result in one LSE being relieved of its entire procurement obligation under D.21-06-035 in this order. *Both LSEs must trade portions of their compliance obligations under this provision.*" (emphasis added).

period. This will enable an LSE who is long to off-set their costs of procuring early and allow an LSE that is short to pay to meet its compliance obligation while ensuring that the overall grid need for those LSEs has been met. This flexible compliance mechanism will ensure reliability at the least cost rather than potentially stranding new capacity during the years it is available but not needed by the LSE that has contracted it, while another LSE faces penalties or incremental new procurement to meet their compliance obligation.

In addition, as discussed in response to question 13, the Commission should continue to prioritize use of the TED task force to help LSEs and developers meet deadlines where delays beyond the control of those parties arise, including through resolving delays in transmission, interconnection, siting, licensing, and permitting.

Finally, if the Commission extends the ability for LSEs to perform baseline swap arrangements as allowed by D.23-02-040, the Commission must incorporate all the provisions regarding those swaps. Notably, this would include the prohibition of a contract terminated after January 13, 2023, from being eligible for a swap to avoid the potential exercise of market power.[78]

26. What other actions should the Commission take specifically to maximize the impact of the availability of existing federal government loans or other contributions, to support energy infrastructure during the 2028 to 2031 period? Be as specific as possible.

As discussed in response to question 13, the Commission should continue its participation in the TED task force to facilitate developers and LSEs bringing resources to commercial operation. With continued issues resulting from supply chain issues, interconnection delays,

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[78] *See* D.23-02-040, *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resource Portfolios to California Independent System Operator for 2023-2024 Transmission Planning Process*, R.20-05-003 (Feb. 28, 2023), at 20: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF.

permitting, siting, licensing difficulties and load forecast uncertainty, the Commission should take every step it can to mitigate causes of delays.

V. OTHER QUESTIONS

27. Please feel free to comment on any other aspect of this ruling that is not covered by the above questions.

The Commission should ensure rules established for the MTR and Supplemental MTR orders are carried over or modified when necessary to apply to any procurement order resulting from this Ruling. *First*, as described in response to question 12, the Commission should clarify that the rules adopted in D.25-09-007 apply to any procurement ordered in response to this Ruling. That is, if an LSE's project is facing a delay and the LSE can demonstrate that it has a contract in place and has met its system RA requirements during the period of delay, then the LSE will be found in compliance.

Second, the Commission should study and clarify how any procurement ordered impacts the Department of Water Resources (DWR) central procurement entity long-lead time resource need determination. D.24-08-064 orders DWR to procure anywhere from zero to 10.6 GW of LLT resources.[79] Should the Commission move forward with a procurement order, it should consider how this procurement order impacts the magnitude of procurement considered by DWR.

Third, as described in response to question 25, the Commission should allow LSEs to trade compliance obligations, without the requirement that "both LSEs must trade portions of their compliance obligations."[80] This will ensure cost-effective compliance by providing LSEs with all reasonable forms of transaction to produce a compliant result without placing reliability at risk.

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[79] D.24-08-064, *Decision Determining Need for Centralized Procurement of Long Lead-Time Resources*, R.20-05-003 (Aug. 29, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M539/K202/539202613.PDF.

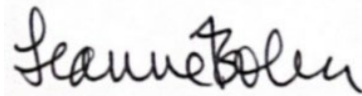
[80] D.23-02-040 at 89, OP 10.

Fourth, as described in response to question 25, if the Commission extends the ability for LSEs to perform baseline swap arrangements as allowed by D.23-02-040, it should prohibit a contract terminated after January 13, 2023, from being eligible for a swap to avoid the potential exercise of market power. Additionally, the Commission should clarify that any new obligation resulting from a swap should be added to the LSE's 2032 obligation.

VI. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments herein.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

October 22, 2025

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON ELECTRICITY PORTFOLIOS FOR 2026-2027 TRANSMISSION PLANNING PROCESS AND NEED FOR ADDITIONAL RELIABILITY PROCUREMENT

CALCCA NEEDS ANALYSIS INPUTS AND ASSUMPTIONS

CALCCA NEEDS ANALYSIS INPUTS AND ASSUMPTIONS

- **Demand:**
  - Load Forecast: CEC 2024 IEPR
  - PRM: 18.5 percent

- **Supply:**
  - Supply resources inside of the CAISO system are composed of online and contracted resources that are expected to come online, with the exclusion of Diablo Canyon Power Plant.
    - Online resources include resources in the Commission's Master Resource Database and CAISO's NQC list published July 2025.
    - Contracted resources include resources expected to come online according to the Commission's Resource Tracking Data.[81]
    - Diablo Canyon Power Plant is excluded from the supply in both 2030 and 2032 based on the assumption that SB 846 precludes the Commission from including Diablo in planning studies.

- **Storage Dispatch:**
  - Storage dispatch is constrained based on the SOD accounting rules. Storage power is limited by the nameplate capacity (MW) rating, storage energy is limited by the energy (MWh) rating, and sufficient charging energy must be available to charge storage, including efficiency losses. Within these constraints storage is dispatched after accounting for all other resources, imports, and adjustments, to maximize the minimum net supply.

- **Imports:**
  - RA imports for each month are based on the actual RA imports reported by the CAISO in 2024 and the Commission's hourly shapes, which achieve the full RA import level in hours 6 through 22 but are as much as 50 percent lower in the other hours of the day.

- **Demand Response:**
  - Demand response quantities are from the Commission's Resource Adequacy Compliance Materials; applied to 5 contiguous hours with highest difference between demand and supply. Demand response totals include avoided losses and are from event-based programs at PG&E, SCE, and SDG&E.

- **Negative Adjustments to Market Supply**
  - **Thermal Plant Derate:**

[81] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-july-2025-release.pdf.

    - Many thermal generators cannot produce maximum output during periods with high ambient temperatures, leading to plant derates. For this reason, resource owners may not sell their full nameplate capacity as RA capacity. For thermal plants whose NQC is listed as equivalent to their Net Dependable Capacity, CalCCA applies a technology-specific thermal derate estimated from historical ambient temperature derates within the CAISO. CalCCA's approach parallels Commission discussions regarding the need to include thermal derates in reliability modeling.

- **Retention for Substitution:**
  - IOUs are entitled to retain RA beyond their bundled needs for substitution during planned outages. This assessment relies on the 2021 resources retained by IOUs as reported in the 2021 IOU Excess Resource reports.

- **Excess IOU Procurement:**
  - The Commission adopted an effective PRM target of 1,260-2,300 MW for June-October (translates to 3-5.5 percent) for 2026 and 2027. The lower end of the effective PRM target, 1260 MW, was used in this analysis.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service	A.24-11-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Katy Morsony,
Senior Counsel and Manager of Strategic Policy Initiatives

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
(510) 980-9459
E-mail: regulatory@cal-cca.org

October 24, 2025

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SUMMARY OF RECOMMENDATIONS[1]

In this brief, CalCCA recommends:

- The information sharing protocols adopted in the Interim Decision should be made permanent. PG&E should be directed by the Commission to send new Rule 30 applications to the impacted CCA within 20 business days of receipt, and to provide customers with notice of CCAs' role as generation provider, and that PG&E will be sharing customer information with the CCA. This information will continue to be protected under the existing PG&E-CCA NDA and Commission requirements without additional privacy requirements.

- Rule 30 Applications should be shared with PG&E's procurement department at the same time they are made available to the CCA.

- PG&E should be directed to share preliminary load information with an impacted CCA at the same time it is provided to the CEC.

- The Commission should continue the quarterly reporting required under the Interim Decision, clarifying that the confidential reports should be shared with impacted CCAs under the existing PG&E-CCA NDA. Projects included in the Quarterly Reports should be assigned a unique project identifier that can be used to track the project through the design and construction process.

- The current PG&E-CCA NDA, along with existing Commission confidentiality requirements, is sufficient to protect customer information and PG&E's proposed new NDA should be rejected. To the extent that the Commission determines a new NDA is required, it should direct the parties to collaborate on a new Rule 30 specific NDA.

- PG&E's proposed PRA and TSR requirements should be rejected as unnecessary given the CCA role as default generation provider. The Commission should reject this attempt to withhold customer information.

- Coordination of service incorporating PG&E's proposal for customers to provide notice of their choice of generation service provider within 45 days of the PES is not properly within the scope of this proceeding or necessary. To the extent that the Commission orders coordination of service, it should direct CalCCA and PG&E to submit a Tier 2 Advice Letter implementing the coordination of service proposal offered below.

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[1] Acronyms used herein are defined in the body of this document.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service	A.24-11-007

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING BRIEF

The California Community Choice Association[2] (CalCCA) submits this Opening Brief regarding the *Application of Pacific Gas and Electric Company (U 39 E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service*,[3] (Application) pursuant to Rule 13.12 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[4] and *Assigned Commissioner's Scoping Memo and Ruling on Pacific Gas and Electric Company's Request to Implement a New Electric Rule 30 Tariff*[5] (Scoping Ruling).

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[2] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[3] *Application of Pacific Gas and Electric Company (U 39 E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service*, Application (A.) 24-11-007 (Nov. 21, 2024).

[4] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021).

[5] *Assigned Commissioner's Scoping Memo and Ruling on Pacific Gas and Electric Company's Request to Implement a New Electric Rule 30 Tariff*, A.24-11-007 (Mar. 11, 2025).

I. INTRODUCTION AND EXECUTIVE SUMMARY

Pacific Gas and Electric Company (PG&E) proposes a new Rule 30 tariff for customers requesting interconnection from PG&E at transmission level voltages between 50 kilovolts (kV) and 230 kV.[6] PG&E propo.ses its tariff to address the recent influx of applications in 2023-2024 for transmission level service, of which many are data centers: PG&E states it "has received 40 active applications for transmission level service with demand of 4 [megawatts (MW)] or greater [and the] total combined current requested load of the 40 applications is 8,422 MW."[7] While PG&E will provide the delivery service to this potentially massive influx of new load, community choice aggregators (CCA) are the default generation service providers for any new load that locates in their service areas. The 11 CCAs in PG&E's service territory provide 46 percent of the electric generation service in PG&E's entire service territory and serve on average 92 percent of customers within their own service territories.[8] Consistent with their primary role serving new customers, CCAs need information on the generation needs of the new load with sufficient time to pursue an efficient and economic procurement strategy.

CalCCA intervened in this proceeding expressly to address the requirements of information sharing. CalCCA's issues are included in the proceeding as Scoping Issue 4.b.: "What information-sharing requirements should PG&E adopt to ensure that the CCAs affected by Rule 30-related load growth can meet projected demand in their service areas."[9] PG&E supported CalCCA's request for the information to be provided on an interim basis under

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6 *Application of Pacific Gas and Electric Company (U 39 E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electrical Service*, A.24-11-007 (Nov. 21, 2024), at 1 (Application).

7 PG&E Testimony, at 4, lines 4-7; *Pacific Gas and Electric Company's (U 39 E) Response to Administrative Law Judge's Ruling Requesting Information on the Motion for Interim Implementation of Electric Rule No. 30 [Public Version],* A.24-11-007 (Apr. 4, 2025), at 8.

8 *See* CalCCA Website, "CCA: Power in Numbers": https://cal-cca.org/cca-impact/.

9 *Assigned Commissioner's Scoping Memo and Ruling*, A.24-11-007 (Mar. 11, 2025) (Scoping Ruling), at 8.

Decision (D.) 25-07-039[10] (Interim Decision) issued in this proceeding, and assents to providing these applications to CCAs on a permanent basis. PG&E has also specified that it will provide the same information, at the same time, to its generation procurement department, which CalCCA agrees is reasonable. In addition, PG&E has committed to providing load forecasting information regarding Rule 30 customers to CCAs at the same time it provides such information to the California Energy Commission (CEC), which CalCCA also agrees is reasonable.

However, PG&E seeks additional conditions, including that CCAs submit to PG&E's cybersecurity and privacy reviews and requirements and sign a new universal, non-disclosure agreement (NDA) even though CCAs already treat customer information confidentially under existing NDAs and Commission requirements. The additional conditions PG&E seeks to place on CCAs would slow the exchange of information and create additional and unnecessary hoops for CCAs to navigate as a precondition to receiving information about their own customers. PG&E also proposes a timeline for a customer to identify its generation provider: 45 days after a preliminary engineering study (PES) is complete. This timeframe represents an unspecified period prior to the customer agreeing to move forward with the interconnection through the execution of an Interconnection Agreement (IA) with PG&E. PG&E's proposal is outside of the scope of this proceeding, but it is also unreasonable given that, at the PES stage, project is still highly uncertain., PG&E's proposal would also reduce customer optionality.

In this brief, CalCCA therefore recommends:

- The information sharing protocols adopted in the Interim Decision should be made permanent. PG&E should be directed by the Commission to send new Rule 30 applications to the impacted CCA within 20 business days of receipt, and to provide customers with notice of CCAs' role as generation provider, and that PG&E will be sharing customer information with the CCA. This information will continue to be

[10] D.25-07-039, *Decision Partly Granting and Partly Denying PG&E's Motion for Interim Implementation of Electric Rule Number 30*, A.24-11-007 (July 28, 2020).

protected under the existing PG&E-CCA NDA and Commission requirements without additional privacy requirements.

- Rule 30 Applications should be shared with PG&E's procurement department at the same time they are made available to the CCA.
- PG&E should be directed to share preliminary load information with an impacted CCA at the same time it is provided to the CEC.
- The Commission should continue the quarterly reporting required under the Interim Decision, clarifying that the confidential reports should be shared with impacted CCAs under the existing PG&E-CCA NDA. Projects included in the Quarterly Reports should be assigned a unique project identifier that can be used to track the project through the design and construction process.
- The current PG&E-CCA NDA, along with existing Commission confidentiality requirements, is sufficient to protect customer information and PG&E's proposed new NDA should be rejected. To the extent that the Commission determines a new NDA is required, it should direct the parties to collaborate on a new Rule 30 specific NDA.
- PG&E's proposed Privacy Risk Assessment (PRA) and Third-Party Cyber-Security Review (TSR) requirements should be rejected as unnecessary given the CCA role as default generation provider.
- Coordination of service incorporating PG&E's proposal for customers to provide notice of their choice of generation service provider within 45 of the PES is not properly within the scope of this proceeding or necessary. To the extent that the Commission orders coordination of service, it should direct CalCCA and PG&E to file a Tier 2 Advice Letter implementing the coordination of service proposal offered below.

The information sharing principles that PG&E and CalCCA have already agreed to will provide both the CCAs and PG&E the opportunity for cost-effective and affordable procurement. PG&E's additional requests are unnecessary and would reduce customer optionality. The Commission should continue the information sharing framework adopted in the Interim Decision with limited clarifications and expansions to ensure that CCAs receive all necessary updates on new large load customers.

II. BACKGROUND

A. Factual Background

Certain facts underlie CCA's position in this proceeding:

- CCAs were enabled through AB 117.[11] As described by the Commission, CCAs as "governmental entities formed by cities and counties to serve the energy requirements of their local residents and businesses."[12]
- Terms and conditions for generation customers of PG&E and the CCAs are memorialized in Rule 23, which includes the process for customers opting out of CCA service and electing to take PG&E bundled service instead.[13]
- PG&E and CalCCA agree that CCAs are the default providers for generation service in the territories that the CCAs serve.[14]
- Given the predicted influx of large loads in the CCAs' service territories, the CCAs must prepare to provide generation service for much of the load, given PG&E has reported that "a significant number of the very large load applications received thus far are for projects within areas service by [CCAs]."[15]
- CCAs need adequate time to cost-effectively procure for Rule 30 large load customers, and therefore need information regarding these customers prior to energization.[16]
- There are currently no standards in place for sharing information between PG&E and CCAs related to new large load customers interconnecting under Rule 30,[17] except for the information sharing approved on an interim basis in the Interim Decision.

B. Procedural Background

Originally, a group of CCAs located in the PG&E territory (Joint CCAs) jointly intervened in this proceeding to represent the needs of their individual CCAs.[18] The Joint CCAs requested that the scope of this proceeding include information sharing related to new large loads.[19] The Scoping Ruling included as Issue 4.b. in this proceeding: "What information-

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[11] Assembly Bill 117, Ch. 838, Stats 2002 (Sept. 24, 2002) (amending Pub. Util. Code Sections 218.3, 366, 394, and 394.25 and adding Sections 331.1, 366.2, and 381.1).

[12] D.04-12-046, *Order Resolving Phase 1 Issues on Pricing and Costs Attributable to Community*, R.03-10-003 (Dec. 16, 2004), at 1.

[13] Exh. PG&E-09, passim.

[14] Exh. CalCCA-01, at 6, lines 23-25; Exh. PG&E-04 at 91, line 29-92, line 2.

[15] *See Pacific Gas and Electric Company's (U 39 E) Response to the California Public Advocates Office's Motion to Amend the General Rate Case Phase II Scoping Memo to Include Issues from Application 24-11-007,* A.24-09-014 (Apr. 17, 2025), at 11 ("in California, retail choice means that PG&E may not be the Load Serving Entity that provides generation service to new very large load customers, even where PG&E is the utility providing delivery services from its transmission or distribution lines. A significant number of the very large load applications received thus far are for projects within areas served by [CCAs], ...").

[16] Exh. Cal-CCA-01, at 9, line 17 to 17, line 2.

[17] Exh. CalCCA-01, at 8, lines 6-7; Exh. PG&E-04, at 9, lines 6-12.

[18] *Response of the Joint Community Choice Aggregators*, A.24-11-007 (Dec. 23, 2024).

[19] *Joint Prehearing Conference Statement*, A.24-11-007 (Jan. 17, 2025), at 3.

sharing requirements should PG&E adopt to ensure that the CCAs affected by Rule 30-related load growth can meet projected demand in their service areas."[20] On June 6, 2025, CalCCA submitted a Motion for Party Status in this proceeding given the "commonality of interests among CCAs and CalCCA's involvement in other, related proceedings."[21] The Commission granted CalCCA's motion on June 18, 2025.[22] On June 18, 2025, CalCCA requested a modification to the procedural schedule to allow for surrebuttal testimony on PG&E's rebuttal testimony, which would be the first time PG&E addressed Issue 4.b. The Administrative Law Judge issued a ruling providing for this schedule modification on June 19, 2025,[23] CalCCA served testimony in this proceeding on June 30, 2025, addressing Issue 4.b.[24] After PG&E addressed Issue 4.b. in its August 19, 2024, Rebuttal Testimony,[25] CalCCA served its Surrebuttal Testimony on September 8, 2025.[26]

Meanwhile, PG&E submitted its Motion for Interim Implementation of the Rule 30 tariff on January 24, 2025 (Interim Motion).[27] The Joint CCAs responded to the Interim Motion on February 10, 2025, recommending that the Interim Motion be denied.[28] The Commission issued a Proposed Decision granting and partly denying the Interim Motion.[29] CalCCA submitted extensive opening comments on the Proposed Decision outlining the policy supporting the

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[20] Scoping Ruling at 8.

[21] *California Community Choice Association's Motion for Party Status*, A.24-11-007 (June 6, 2025), at 3.

[22] *E-Mail Ruling Granting CalCCA's Motion for Party* Status, A.24-11-007 (June 18, 2025), at 1.

[23] *E-Mail Ruling Modifying the Procedural Schedule*, A.24-11-007 (June 19, 2025), at 1.

[24] Exh. CalCCA-01.

[25] Exh. PG&E-04, at 90-102.

[26] Exh. CalCCA-02.

[27] *PG&E's Motion for Interim Implementation of Electric Rule 30*, A.24-11-007 (Jan. 24, 2025).

[28] *Response of the Joint Community Choice Aggregators to PG&E's Motion for Interim Implementation*, A.24-11-007 (Feb. 10, 2025), at 2.

[29] Proposed *Decision Partly Granting and Partly Denying PG&E's Motion for Interim Implementation of Electric Rule Number 30*, A.24-11-007 (June 20, 2025).

implementation of CalCCA's proposed information sharing principles on an interim basis.[30] PG&E and CalCCA each submitted reply comments on the Proposed Decision highlighting the common position agreed to by the parties regarding information sharing and recommending modifications to the Proposed Decision to reflect this agreement.[31] Consistent with the PG&E and CalCCA comments, the Interim Decision directs PG&E to share applications for Rule 30 interconnection within 20 business days with any impacted CCA and institutes quarterly reporting.[32] The Interim Decision is discussed further throughout Section III.D.2.b. below.

C. Policy Issues: CCA Policy Position

CalCCA's governing principle for information-sharing requirements is that ***when PG&E receives information on a new large load, the default provider CCA should also receive that information consistent with confidentiality requirements, to enable the CCA to work with the customer and maximize the potential for efficient procurement—there is no justification for delay***.[33] Consistent with this principle, CalCCA's proposals in this proceeding all serve to maximize the optionality for new large loads locating in California.

III. DISCUSSION

A. Issue 1 – Reasonableness: Are the provisions of Electric Rule 30 just and reasonable for the new transmission level customers and the existing ratepayers?

CalCCA takes no position on Issue 1 or its subparts.

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30 *CalCCA's Comments on the Proposed Decision Partly Granting and Partly Denying PG&E's Motion for Interim Implementation of Electric Rule Number 30*, A.24-11-007 (July 10, 2025) (CalCCA PD Comments).

31 *PG&E's Reply Comments on Proposed Decision Regarding Interim Implementation*, A.24-11-007 (July 15, 2025) at 1-2 (PG&E PD Reply Comments); *CalCCA's Reply Comments on the Proposed Decision Partly Granting and Partly Denying PG&E's Motion for Interim Implementation of Electric Rule Number 30*, A.24-11-007 (July 15, 2025), at 1-2.

32 D.25-07-039, Ordering Paragraphs (OP) 6-7, at 52-53.

33 Exh. CalCCA-01 at 5, lines 1-4; Exh. CalCCA-02, at 2, lines 21-24.

1. **Issue 1.a: Is the current process for customers requesting electric service at transmission voltages efficient and adequate?**

B. Issue 2 – Jurisdiction, Statutes, and Decisions: Does Electric Rule 30 align with existing laws, regulations, or other Commission decisions?

CalCCA takes no position on Issue 2 or its subparts.

1. **Issue 2.a: How should the Commission determine what parts of PG&E's Rule 30 proposal are within the CPUC or FERC's jurisdiction?**

2. **Issue 2.b: Is Section 783 applicable to Electric Rule 30?**

C. Issue 3 - Rates, Cost Causation, and Allocation: For each of the four electrical facility types to interconnect customers at the transmission level – Facility Type 1: Transmission Service Facilities, Facility Type 2: Transmission Interconnection Upgrades, Facility Type 3: Transmission Interconnection Network Upgrades, and Facility Type 4: Transmission Network Upgrades –

CalCCA takes no position on Issue 3 or its subparts.

1. **Issue 3.a: How should the Commission determine cost causation to ensure that beneficiaries pay for Facility Types 1-4?**

2. **Issue 3.b: Is there a jurisdictional split between FERC and CPUC costs for these transmission-level load interconnections for Facility Types 1-4? If so, what is the split?**

3. **Issue 3.c: How should PG&E account for and recover costs accrued under CPUC jurisdictional rates and those under FERC jurisdictional rates?**

4. **Issue 3.d: How should the Commission allocate the cost of new transmission-level infrastructure between existing ratepayers and the transmission-level applicant to ensure the allocation of costs is commensurate with the benefits of the facilities for ratepayers and the applicant?**

5. **Issue 3.e: How will the load from new transmission-level customers affect electric service and reliability, electric utility revenue requirement, and electric rates for existing customers?**

6. **Issue 3.f: Are the proposed refund provisions of customer Advances, Actual Cost Payments, and reimbursement for Contributions and costs associated with Applicant Build Facilities over a 10-year period**

reasonable? If so, why? If not, what alternative should the Commission consider?

7. **Issue 3.g: Is PG&E's Base Annual Refund Process (BARC) a reasonable methodology to determine when applicants are eligible for refunds?**

8. **Issue 3.h: What is the process and timeline for adding costs, including refunds for new facilities to the ratebase (for all impacted jurisdictions)?**

9. **Issue 3.i: Is it reasonable for PG&E to provide outstanding refunds to subsequent customers prior to or during the refund period based on the use of Transmission Interconnection Upgrades (Facility Type 2) and/or Transmission Interconnection Network Upgrades (Facility Type 3)?**

10. **Issue 3.j: Is PG&E's proposal to enter into a pre-funding loan to build Transmission Network Upgrades reasonable? How will this impact ratemaking?**

11. **Issue 3.k: Does Rule 30 sufficiently protect ratepayers from financial risk from stranded costs and/or make ratepayers whole for any shortfall between the projected and actual revenue and load from Rule 30 customers over the 10-year reimbursement period? If not, what additional rules should the Commission adopt?**

D. ISSUE 4: Reporting

1. **Issue 4.a: Should the Commission establish reporting requirements for these Transmission level projects in this proceeding to inform related electric system planning processes? For example, reporting of projected load from Rule 30 customers could help to inform load forecasting.**

CalCCA's recommendation regarding reporting requirements for Transmission level projects and/or projected load from Rule 30 customers, to inform load forecasting and for CCA procurement purposes, is set forth in its answer to Issue 4.b below.

2. **Issue 4.b: What information sharing requirements should PG&E adopt to ensure that the CCAs affected by Rule 30 related load growth can meet projected demand in their service areas?**

As noted above, CalCCA's governing principle for information-sharing requirements is that ***when PG&E receives information on a new large load, the default provider CCA should***

also receive that information consistent with confidentiality requirements, to enable the CCA to work with the customer and maximize the potential for efficient procurement—there is no justification for delay.[34] The Commission has approved information sharing consistent with this principle on an interim basis in the Interim Decision. The Commission should adopt the same information-sharing requirements on a permanent basis and reject PG&E's additional proposed conditions as unnecessary and/or out of scope.

a. California Law and Commission-Approved Electric Rules Establish CCAs as the Default Providers of Generation Service, as PG&E acknowledges

All currently operating CCAs serve as the default providers of generation service for all customers (residential and non-residential) in their service areas, subject to each customer's ability to opt out of CCA service.[35] CCA customers continue to receive delivery service from the investor-owned utility (IOU) serving their location. Consistent with their role as default providers, CCAs currently provide 46 percent of electric generation service in PG&E's entire service territory (including areas of PG&E's service territory not served by a CCA).[36]

California Public Utilities Code section 366.2(b),[37] the statute enabling CCAs, requires any potential public agency seeking to operate a CCA to "offer the opportunity to purchase electricity to all residential customers within its jurisdiction."[38] While the statute does not explicitly require a CCA to offer non-residential service, it does require that the CCA offer to its

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[34] Exh. CalCCA-01 at 5, lines 1-4; Exh. CalCCA-02, at 2, lines 21-24.

[35] 3 TR 416:11-13 (CalCCA Mitchell).

[36] Exh. CalCCA-001 at 6, citing, *California Energy Demand 2023 Baseline LSE and BAA Tables*, Form 1.1c (energy demand for 2023): https://efiling.energy.ca.gov/GetDocument.aspx?tn=255153. *See also* D.24-12-038, *Decision Approving Pacific Gas and Electric Company's 2025 Energy Resource Recovery Account Related Forecast Revenue Requirement and 2025 Electric Sales Forecast*, A.24-05-009 (Dec. 19, 2024), at 38 ("PG&E expects CCA and [Direct Access] providers to serve nearly two-thirds of total system sales in 2025.").

[37] All Section references hereinafter are to the California Public Utilities Code unless otherwise stated.

[38] Section 366.2(b).

customers "universal access"[39] and "equitable treatment of all classes of customers."[40] While under strict statutory language, a new CCA forming could have the opportunity to only serve residential customers, to the extent that a CCA offers non-residential service, the CCA is required to offer its customers universal access and equitable treatment. Currently, all operating CCAs offer non-residential service.[41]

The choice of service provider solely belongs to the customer. Once the CCA offers service, it is bound to serve customers in its service territory subject to each customer's choice to opt out. Section 366.2(c)(2) directs that "[i]f no negative declaration is made by a customer, that customer *shall be* served through the community choice aggregation program."[42] PG&E's Electric Rule 23.K.2 directs that "[c]ustomers establishing electric service within a CCA service area shall be automatically enrolled in CCA Service *at the time their electric service becomes active* unless the customer submits a request to the CCA to opt-out and the CCA provides notification to PG&E of any such opt out request."[43] Electric Rule 23.G. further specifies that if a customer is in a CCA service area and does not opt out of CCA service, the CCA will serve the customer.[44] PG&E testified that it "agrees with this interpretation and understands that, unless a potential transmission customer located in a CCA's service area opts out of CCA service, that customer will be provided with generation service by the CCA."[45] As the legally recognized,

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39 Section 366.2(c)(4).
40 Section 366.2(c)(6).
41 3 TR 430:9-12 (CalCCA Mitchell).
42 Section 366.2(c)(2) (emphasis added).
43 Exh. PG&E-09 at Sheet 32 (emphasis added).
44 *Id.*, Sheet 25 ("Pursuant to D.05-12-041, all customers, including active Direct Access customers, located within a CCA's service area that have been offered service by the CCA that do not affirmatively decline such service (opt-out), shall be served by the CCA.").
45 Exh. PGE-04 at 91, line 29-92, line 2.

acknowledged, and established default provider of generation service to these new customers, information on the new loads should be provided to CCAs with no undue delay.

b. CalCCA's Recommended Information-Sharing Requirements Adopted in the Interim Decision are Supported by PG&E and Should be Adopted Permanently

Consistent with CalCCA's governing principle in this proceeding, CalCCA's testimony in this proceeding recommends the following information sharing requirements:

- **Load Inquiries Prior to Interconnection Application.** For loads for which no application for interconnection service under Rule 30 (Interconnection Application) has been submitted to PG&E, but a load inquiry has been made to PG&E and PG&E is incorporating the forecast into internal or external forecasts, PG&E should report to CCAs on a quarterly basis the approximate location, size, and anticipated timeline for integrating the new load. Information should be provided on a per-project basis with a unique identifier that protects the customer's identity if the customer does not wish to have their information shared with the CCA.

- **Post-Interconnection Application.** When an Interconnection Application has been submitted, PG&E should provide each affected CCA a copy of the Interconnection Application within 20 calendar days of submission to PG&E, as further described below in Section III.B., customer name, location, facility type (*e.g.,* data center, commercial, retail, manufacturing), capacity ramp schedule, on-site generation, and requested and current expected timing for the interconnection (Key Large Load Information).[11] PG&E should also provide all already submitted IA, and any additional Key Large Load Information, to an affected CCA within 20 calendar days of a Commission directive to do so.

- **Quarterly Reports.** PG&E should provide each affected CCA with quarterly reports that provide updates on the proposed interconnection timelines related to Interconnection Applications, and any changes to Key Large Load Information.[46]

CalCCA's proposed information sharing requirements would provide any impacted CCA with the information required to work with new Rule 30 customers on their procurement needs at the earliest reasonable point in the process. Additionally, the CCA would receive regular updates regarding when certain milestones occur. CalCCA made these same proposals in response to the

[46] Exh. CalCCA-01 at 4, lines 9-34.

Proposed Decision on interim implementation of the Rule 30 Tariff.[47] Throughout the pendency of this proceeding, CalCCA and PG&E have reached agreement on CalCCA's proposals as described further below.

In comments on the Proposed Decision on the Interim Motion, PG&E agreed to the CalCCA information sharing proposal for applications within 20 business days and quarterly reporting.[48] Notably, PG&E did not agree to sharing information regarding load inquiries on an interim basis.[49] The Interim Decision adopted the agreed-on proposals and found that "CCAs and other load serving entities can utilize timely information for resource planning and reliability in response to the system load."[50] The Interim Decision currently directs PG&E to:

- Share Applications for Rule 30 Interconnection with the impacted CCA within 20 business days of receipt. The information is shared pursuant to D.12-08-045,[51] including the existing NDA between PG&E and each CCA, and without any additional requirements.[52]

- Notice customers regarding the role of CCAs and information sharing with CCAs within 20 business days of the customer's submission of a Transmission Interconnection Application with PG&E.[53]

- Share updated customer information through quarterly reporting to the Commission and parties to the proceeding, describing customer Rule 30 agreements for transmission project work, updates on the transmission interconnection timeline, changes to key customer information, and any lessons learned to date based on the interim implementation. PG&E's first quarterly report was due for the calendar quarter immediately following the adoption date of the decision.[54]

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47 CalCCA PD Comments at 2-3.
48 PG&E PD Reply Comments at 1-2.
49 PG&E PD Reply Comments at 1-2.
50 D.25-07-039, at 47, Finding of Fact 30.
51 D.12-08-045, *Decision Extending Privacy Protections to Customers of Gas Corporations and Community Choice Aggregators, and to Residential and Small Commercial Customers of Electric Service Providers*, R.08-12-009 (Aug. 23, 2012).
52 Interim Decision at 52-53, OP 7.
53 *Id.* at 55, OP 7.
54 *Id.* at 38, at 49, Conclusion of Law 13.

PG&E's rebuttal testimony, submitted after the Interim Decision, reflects significant additional areas of agreement between PG&E and CalCCA which will make permanent the interim information-sharing requirements directed by the Interim Decision. Specifically, CalCCA and PG&E agree that:

- Large loads customers have an opportunity of choosing where they locate.[55]
- As discussed further in section III.D.2.a. above, CCAs are the default providers of generation service in their service territories.[56]
- It is reasonable to share new applications for Rule 30 Interconnection within 20 business days with both the affected CCA and PG&E's Energy Procurement Organization.[57]
- The Rule 30 Tariff should include an updated retail service definition specifying application of the tariff to delivery service as well as notice to applicants that their information will be shared with the impacted CCA in both the tariff and Rule 30 Application.[58]

PG&E also agrees that the quarterly reporting required under the Interim Decision should continue under the permanent adoption of the tariff.[59] CalCCA recommends limited clarifications to the quarterly reports:

- Confidential versions of any reports sent to the Commission should be provided simultaneously with the affected CCA(s) subject to the existing PG&E-CCA NDA.[60]

- Projects should be given a project identification numbers that allow the Commission, CCA and PG&E to clearly track progress of projects through the process and will inform consideration of future large load demand.[61]

- The Commission should direct PG&E to hold meetings to discuss the Quarterly Reports as requested by CCAs to address any questions of clarifications on the content of the reports.[62]

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55 Exh. PG&E-04 at 91, lines 16-19; Exh. CalCCA-01 at 4, lines 11-18.
56 Exh. CalCCA-01 at 6, line 20 to9, line 14; Exh. PG&E-04 at 91, line 21-92. Line 2.
57 Exh. CalCCA-02 at 3, line 43 to 4, line 56; Exh. PG&E-04 at 95, line 22-96, line 2; PG&E-04 at 101, lines 5-13.
58 Exh. CalCCA-01 at 9, line 1-20, line 22; Exh. PG&E-04 at 96, line 7 to 97, line 9.
59 Exh. PG&E-04 at 96, lines 3-6.
60 Exh. CalCCA-02 at 4, line 62 to 5, line 69.
61 *Id.* at 5, lines 71-74.
62 Exh. CalCCA-02 at 5, lines 79-83.

These limited clarifications do not materially impact the resources required for the quarterly report and should be adopted in a final decision.

In addition, PG&E proposes and CalCCA agrees that information on Rule 30 load forecasts should be shared with impacted CCAs when that information is shared with the CEC.[63] Among other data points, the CCA procurement strategy is informed by the Integrated Energy Policy Report (IEPR) published by the CEC, and receiving only the aggregate load forecast from the IEPR is insufficient information for planning for new loads.[64] Consistent with these information needs, CalCCA proposed that PG&E provide the data underlying its forecasts of load with the CCAs.[65] Between Rebuttal and Surrebuttal Testimony, PG&E agreed to provide the "load inquiry shared with the CEC at the same time PG&E shares it with the CEC" under the terms of the NDA.[66] The final decision in this proceeding should memorialize this agreement.

c. PG&E's Proposed Additional Hurdles Will Undermine Efficient Coordination Between PG&E and CCAs

While PG&E agrees that it is reasonable for Rule 30 Applications to be shared with the affected CCA(s), it proposes new requirements before PG&E shares information on the CCA's own customer with the CCA. PG&E proposes the Commission:

- Require a new universal NDA to replace the existing NDA between the CCAs and PG&E which already provides adequate protection regarding customer information;[67]
- Grant PG&E authority to require any CCA receiving Rule 30 information to complete PG&E cybersecurity and privacy reviews;[68] and
- Adopt timelines for coordination of service between PG&E and the CCA for Rule 30 customer loads, including timelines for the Rule 30 customer to provide notice to the

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63 *Id.* at 3, lines 30-39.
64 Exh. CalCCA-01 at 13, line 15 to 14, line 4.
65 *Id.* at 5, lines 7-15.
66 Exh. CalCCA-02 at 3, lines 35-39.
67 Exh. PG&E-04 at 97, line 26 to 99, line 21.
68 *Id.* at 99, line 187 to 101, line 4.

CCA and PG&E whether the customer will take default service from the CCA or has elected to receive service from PG&E.[69]

As demonstrated below, these proposals are unnecessary, inconsistent with Commission precedent, and/or out of scope for this proceeding. Therefore, PG&E's proposals should be rejected and not be a part of any permanent approval of the Rule 30 Tariff.

i. PG&E's Proposal for a New Universal NDA Should be Rejected as the Existing Universal NDA Provides Adequate Protection, as Confirmed by the Interim Decision

PG&E's proposal for a new universal NDA should be rejected as the existing universal NDA required by the Commission provides adequate protection, as confirmed by the Interim Decision. As acknowledged by PG&E, there is a current NDA in place between PG&E and each CCA: "the NDA was last approved by the Commission on February 4, 2021 in connection with AL 6050-E ("2021 CCA NDA"). The form NDA is currently reflected in PG&E Sample Form No. 79-1031."[70] Pursuant to the Interim Decision, the Rule 30 Application information is being shared with the CCAs on an interim basis pursuant to this existing NDA and the confidentiality protections set forth in D.12-08-045.

PG&E requests that the Commission adopt a new "comprehensive NDA that will protect all confidential PG&E and customer information shared with CCAs."[71] According to PG&E, the new NDA "closely mirrors the language found in [the] 2021 CCA NDA"[72] and also "incorporates language from the [Emergency Load Reduction Program] NDA."[73]

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[69] *Id.* at 101, line 15 to 102, line21.
[70] *Id.* at 98, lines 1-4.
[71] *Id.* at 98, lines 7-8.
[72] *Id.* at 98, line 14.
[73] *Id.* at 98, line 25.

PG&E does not provide any evidence or argument to explain why the existing NDA provides sufficient protection, as confirmed by the Interim Decision, but a new NDA is required to provide this information on a permanent basis. The current NDA, as noted by PG&E, is explicitly approved by the Commission; there is no explanation for why its terms now do not provide sufficient protection.

The Commission should reject this proposal as:

- Existing law and Commission precedent obligate PG&E to continue to provide relevant customer information to CCAs under existing NDAs;
- PG&E's proposal to replace the existing NDA framework exceeds the scope of this proceeding; and
- PG&E's reliance on the Emergency Load Reduction Program (ELRP) is misplaced as the ELRP terms are unapproved.

To the extent that the Commission believes changes to the existing NDA are required, the Commission should direct parties to collaborate on a new, narrow NDA for the purposes of Rule 30 only. The resulting NDA should be submitted to the Commission via a Tier 2 Advice Letter within 60 days.

(a) Existing Law and Commission Precedent Obligate PG&E to Continue to Provide Relevant Customer Information to CCAs Under the Existing NDA

Section 366.2(c)(9) requires IOUs to "cooperate fully with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs."[74] The Commission interpreted section 366.2 to provide the CCAs, potential or established, with information on *all* customers, whether the customer is with the utility or the CCA:

[74] Section 366.2(c)(9).

> [W]e read the plain language of the statute to mean relevant information must be provided on demand, without distinguishing between a customer who is still with the utility or a customer of the CCA or between the time a CCA is created and the time it provides service. By law, CCAs are entitled to receive certain types of information as long as they are investigating, pursuing or implementing a CCA program.[75]

The Commission goes on to highlight that section 366.2(c)(13)(A) requires the CCA to take responsibility for opt-out notices, and "the CCA cannot satisfy this responsibility without access to customer names and addresses."[76] The Commission concludes "if the Legislature had intended for customer information to remain with the utility, it would have not required the CCA to issue the opt-out notices."[77]

Consistent with its interpretation of the statute, the Commission in D.04-12-046 directs the IOUs to:

> [P]rovide all relevant usage information, load data and customer information to CCAs. *The CCA shall sign nondisclosure agreements for any confidential information that is not masked or aggregated.* We will also require that all notices relevant to CCA programs inform customers that the utility may share customer information with the CCA and that the CCA may not use the utility's information for any purpose other than to facilitate provision of energy services.[78]

The Commission further agreed with the assumption in the CCA enabling legislation (AB 117) that "CCAs can be entrusted with confidential customer information."[79] Consistent with this direction, all CCAs have executed NDAs with PG&E which have been reviewed by the Commission.[80]

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75 D.04-12-046, at 50.
76 *Id.*
77 *Id.*
78 D.04-12-046, at 52 (emphasis added).
79 *Id.* at 51.
80 PG&E-04 at 97, line 28 to 98, line 4.

In D.12-08-045, the Commission made various additional determinations with respect to CCAs' access to and responsibility for customer information.[81] The Commission was clear that CCAs' access to and use of customer information are on par with the IOUs' access to and use of such information. The Commission cited its "full authority to require CCAs which receive . . . data from [the IOUs] to comply with privacy rules," and stated that its privacy policy broadly affords "CCAs with all rights to data that it requests."[82] The only condition for access to customer information is that the CCA enter into an NDA with the IOU, which all CCAs have.[83] The existing NDAs between PG&E and the CCAs "govern the disclosure of [PG&E's] confidential customer information to CCA" to "implement CCA pursuant to [Section 366.2]. . . ."[84] Given the Commission's directives and that PG&E and each CCA already have existing NDAs covering such customer information, PG&E should provide the CCAs with the Rule 30 customer information subject to the existing NDA.

The Interim Decision directed that PG&E provide the CCAs with information on the new Rule 30 customers subject to the existing NDA and Commission directives. Further, as noted by PG&E itself, the terms of the new NDA "closely mirror" the terms of the existing NDA.[85] Requesting that the CCAs now negotiate and sign a new comprehensive NDA, which closely mirrors the NDA already in place, to receive information that is already being shared with them, would be an unnecessary step to providing CCAs with information on their own customers.

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81 D.12-08-045 at 4, 23-26.

82 *Id.*

83 *Id.*

84 PG&E-04 at AtchJ-1. This attachment is a redline of the existing NDA, PG&E Form 79-1031.

85 *Id.* at 98, lines 12-14.

(b) PG&E's Proposal to Replace the Existing NDA Framework Exceeds the Scope of this Proceeding and Should Be Rejected

It is outside of the reasonable scope of this proceeding to adopt a new universal NDA for all PG&E CCAs. While the Scoping Ruling identified information sharing between CCAs and PG&E as an issue in this proceeding, the information sharing is related to Rule 30 only. PG&E, however, seeks approval of a new universal NDA that would replace the current NDA between PG&E and all the CCAs, a reach far beyond the Rule 30 information sharing.[86]

Further, this is an unreasonable approach given that it is not necessarily the case that every CCA in PG&E's territory will receive Rule 30 Applications from PG&E and if they do, will receive it at the same time. Some CCAs may not have any load requiring a Rule 30 application given their geography, population, and other attributes. Even if all CCAs ultimately receive Rule 30 applications, they will likely come in at different times, with each CCA entering into the NDA at a different time. Ultimately, as CCAs are required to enter into a new and different agreement with PG&E , the result could be a patchwork of NDAs covering the different CCAs. To the extent that PG&E believes a new universal NDA is necessary, it should pursue these changes in a venue that has a broader scope.

(c) PG&E's Reliance on the ELRP NDA is Misplaced as the ELRP Terms are Unapproved

PG&E highlights that "[t]he proposed NDA incorporates language from the ELRP NDA in its sections on compliance with applicable law and the security measures required to protect confidential information."[87] In the ELRP proceeding, the Joint CCAs have proposed information

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[86] Exh. PG&E-04 at 97, line 28 to 98, line 9.

[87] *Id.* at 98, lines 25-27.

sharing *on programs* offered by the CCA to ensure that there is not dual enrollment.[88] The Commission directed PG&E "to work with the CCAs to develop a non-disclosure agreement modeled after the one used to prevent dual enrollment in energy efficiency."[89] The Commission, however, did not order PG&E to file the ELRP NDA and the Commission has never previously approved the ELRP NDA language.[90] Certain CCAs have not signed the proposed ELRP NDA because the terms PG&E requires are unacceptable to those CCAs.

(d) Any Changes to the NDA Should be Narrow and Reflect Collaboration on its Terms

PG&E suggests the type of information being shared as a justification for a new NDA: "the new draft NDA also references the types of information that will be shared …such as retail transmission applications, PES reports, and executed Interconnection Agreements."[91] The existing NDA, however, is sufficient for sharing Rule 30 application information, especially in light of the information already being shared under the Interim Decision.

However, if the Commission determines that a new NDA must be adopted for PG&E to provide the Rule 30 information on a permanent basis, the Commission should direct CalCCA and PG&E to work together to adopt a new narrow expansion of the approved NDA incorporating the Rule 30 specific information that will be submitted to the Commission as a form agreement via a Tier 2 Advice Letter within 60 days of the final decision in this proceeding. This new Rule 30 NDA should be in addition to, and should not replace, the existing universal NDAs in place between PG&E and the CCAs.

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88 D.23-12-005, *Decision Directing Certain Investor-Owned Utilities' Demand Response Programs, Pilots, and Budgets for the Years 2024-2027*, A.22-05-002, A.22-05-003, A.22-05-004 (Dec. 14, 2023), at 178-180.

89 *Id.* at 219, OP 11.

90 *Id*.

91 Exh. PG&E-04 at 98, lines 17-20.

ii. PG&E Should Not Be Allowed to Withold Rule 30 Customer Information Pending Cybersecurity or Privacy Reviews

PG&E proposes that it be allowed to submit the CCAs to PG&E's own PRA and TSR before PG&E shares the Rule 30 information with the CCA. While some CCAs in years past agreed to such review unrelated to large load customers,[92] some have not. And no CCA has acquiesced to PG&E's request in relation to Rule 30 applications. Under the Interim Decision, the Rule 30 Application information is being shared with the CCAs now, under the existing NDAs, without the PRA or TSR requirements,[93] even though not all CCAs have completed the PRA and TSR.[94] If PG&E's proposal were to be adopted, it would give PG&E sole discretion to withhold information on the CCA's own customers, delaying the delivery of customer information. The Commission should reject this proposal as:

- CCAs are government entities and should not be subject to vendor-like oversight;
- The voluntary actions of some CCAs is not evidence that the PRA and TSR are reasonable requirements; and
- Contrary to Commission precedent, the imposition of the PRA or TSR requirements could delay CCA access to its own customer information.

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[92] 3 TR 335:5-9 (PG&E Guttierez): "Q Okay. Did Pioneer Clean Energy, San Jose Clean ·Energy, MCE, Redwood Coast Clean Energy -- and Redwood Coast Clean Energy all voluntarily participate in the TSRs A Yes."; 3 TR 337:7-10 (PG&E Guttierez): "Were these all done voluntarily on behalf of the CCAs? In other words, did the CCAs voluntarily participate in the PRA? A Yeah."

[93] 3 TR 345:8-12 (PG&E Guttierez): "Is PG&E currently providing that information under the interim decision in this case to CCAs? A Yes, we did. Sorry. We provided applications to them right after the case -- the interim case was approved."

[94] 3 TR 330:17-331:2 (PG&E Guttierez): "Q Has PG&E completed a third-party cybersecurity review on every CCA with which it currently shares customer information? A For Rule 30? Q Just under existing rules. A· Oh.· Everyone? No. Q Okay. What about the privacy -- privacy risk assessment? It's PRA. A PRA. Q Has that been completed on all CCAs with which you currently share customer information? A No, it has not, on all of them; but, there are a number that have gone through the processes."

(a) CCAs are Government Entities and the Commission Should Reject PG&E's Attempt to Impose Vendor-Like Oversight

It is not necessary for CCAs to undergo the same scrutiny as PG&E's third-party vendors to receive customer information from PG&E. CCAs are not third-party vendors. Instead, as stated by the Commission:

> AB 117 assumes, as we do, that CCAs can be entrusted with confidential customer information. Unlike energy service providers offering direct access, CCAs are *government agencies.* As long as some basic protections are in place, the risks of providing confidential information to these entities is outweighed by the dictates of the statute and the potential benefits CCA customers would realize only if CCAs have the information they need to make fully informed decisions regarding energy procurement, service requirements and resource planning decisions.[95]

In D.05-12-041, the Commission affirmed the protections provided to CCA customers by virtue of the CCA's status as government entities: "We are confident that existing law protects CCA customers. Entities of local government, such as CCAs, are subject to numerous laws that will have the effect of protecting CCA customers and promoting accountability by CCAs."[96] In addition and as noted above, the CCAs are subject to the Commission's oversight on the security of their customer's information,[97] including the requirements of D.12-08-045.[98]

Rather than acknowledging the special role that CCAs play in generation services and that the CCAs have already signed NDAs, PG&E seeks to insert itself into the role of sole gatekeeper over customer information by requiring the CCA to complete a PG&E-designed PRA and TSR before PG&E will provide customer information. PG&E's witness confirmed that,

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95 D.04-12-046 at 51 (emphasis added).

96 D.05-12-041, *Decision Resolving Phase 2 Issues on Implementation of Community Choice Aggregation Program and Related Matters*, R.03-10-003 (Dec. 15, 2005), at 10.

97 Exh, CalCCA-002 at 6, lines 100-101.

98 Exh. CalCCA-002 at 7, line 116.

under its proposal, the utility would require CCA's to make changes to confirm to its TSR before sharing Rule 30 applications.[99] No Load-Serving Entity (LSE) should have the authority to subject other LSEs to a review process that it alone designed, controlled, and implements.

Further, PG&E suggests that it can require changes to CCA cyber-security practices: "any deviations from PG&E standards for cybersecurity needs to be *promptly remediated.*"[100] As an initial matter, PG&E's statement ignores that a CCA could have more stringent cyber-security practices than PG&E. More importantly, PG&E, an investor-owned corporation, should not dictate the cyber-security practices of local government entities. Lastly, allowing PG&E's request provides PG&E with the sole ability to shift the goalposts by to modifying its PRA and TSR to whatever PG&E alone decides is reasonable at any time - and then to deny customer information to its competitors based on PG&E's own subjective determination. The Commission should refuse to provide PG&E this power.

(b) PG&E Cannot Justify Mandatory Cybersecurity and Privacy Review on the Voluntary Actions of Some CCAs

PG&E points to the fact that in the past, certain CCAs have completed the PRA and TSR as evidence that it is reasonable for PG&E to adopt this gatekeeper role for *all* CCAs. Certain CCAs' voluntary submission to these reviews does not make it reasonable for the reviews to become a requirement.[101] PG&E acknowledges that the CCAs that have completed the PRA and

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[99] 3 TR 329:18-24 (PG&E Gutierrez): "· Q If -- if your testimony -- if your proposal and your testimony was adopted by the Commission, if you found that you wanted to change a CCA's cybersecurity proposal -- or cybersecurity rule, if PG&E requested that change, you could require the CCA to make that change before you shared the application.· Correct? A That's my understanding."

[100] Exh. PG&E-04 at 100, lines 3-4 (emphasis added).

[101] Exh. CalCCA-002 at 6, lines 106-108.

TSRs did so voluntarily.[102] Some of these PRA and TSRs were completed in the context of the CCA participating in Energy Efficiency and ELRP programs.[103] Some CCAs choosing to voluntarily participate in these reviews for programs is not evidence that this requirement is reasonable for all CCA generation services.

(c) PG&E Should Not Be Allowed to Use PRA or TSR Requirements to Delay CCA Access to its Own Customer Information

As described by the Commission, "AB 117 does not permit the utilities to second guess a CCA's request for relevant information."[104] Instead the Commission has interpreted AB 117 "to mean relevant information must be provided on demand."[105] If nothing else, PG&E's proposed requirement introduces the potential for delay, a tactic which the Commission has soundly rejected: "While we welcome the utilities' tariff proposals for the secure and cost-effective sharing of information, we will not tolerate utility actions or delays that may affect the provision of information to CCAs or CCA services to customers."[106]

Notably, a requirement that CCAs first complete the PRA and TSR would potentially put PG&E and the CCAs on unequal, and anti-competitive footing. PG&E proposes a new requirement for only the CCAs (its competitors), one its own procurement division would not necessarily need to complete.[107] Meanwhile, under PG&E's proposal, the CCAs would be

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102 3 TR 335:5-9 (PG&E Guttierrez): "Q Okay. Did Pioneer Clean Energy, San Jose Clean Energy, MCE, Redwood Coast Clean Energy -- and Redwood Coast Clean Energy all voluntarily participate in the TSRs -- A Yes."

103 Exh. PG&E-11, CalCCA_001-Q02, CalCCA_001-Q03: During cross-examination, PG&E Witness Gutierrez suggested that at least some of the PRA and TSR were completed related to participation in Energy Efficiency. 3 TR 335:18-24 (PG&E Gutierrez).

104 D.05-12-041 at 39.

105 D.04-12-046 at 50.

106 *Id.* at 53.

107 3 TR 329: 6-11 (PG&E Gutierrez): "Would PG&E impose the same cybersecurity and privacy checks on its own procurement departments before sharing the data internally? A I have not been a part of any conversations between the group that would handle that and our own procurement group."

subject to PG&E's requirement that the CCA change its own cyber-security or privacy practices, adjustments that could take significant time, delaying the delivery of the customer information to the CCA. Consistent with precedent, the Commission should not tolerate this potential delayed delivery of information on the CCAs own customers.

iii. PG&E's Proposed Coordination of Service Proposal is Beyond the Scope and Incomplete

The large size of the Rule 30 loads necessitates that the new load's generation provider have adequate notice of the potential load and the time necessary to procure resources sufficient to serve the new customer.[108] Early information, from the information that the CCA will receive at the same time as the CEC, to the more formal application, will assist the CCA in pursuing a cost-effective long, medium, and short-term procurement strategy. Further, early notice of these customers allows the CCA and PG&E to develop relationships with the customer, get to know the customer's energy needs, and develop a service offering for that customer. Ultimately, it is the responsibility of the CCA and PG&E to use information on the load forecasts and their own business judgement to manage the risks related to large load procurement.

Under current practices, procurement is the responsibility of every generation provider and informed by the IEPR load forecast. The impact of this forecast on procurement strategies underlies the CCA request for, and PG&E' agreement to provide, the information provided to the CEC to develop IEPR load forecasts. Ultimately, the load forecasts will provide an early indicator to the CCAs, and PG&E of the needed procurement and each entity can develop its own strategy to address its procurement needs.

Instead of managing its risk consistent with the information PG&E has, PG&E requests that the Commission adopt a deadline of 45 days after the completion of the PES for a customer

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[108] Exh. CalCCA-01 at 16, lines 9-22.

to provide notice of its intent to opt out of CCA service for PG&E bundled service. The Commission should reject PG&E's proposal, because the proposal:

- Goes beyond information sharing and is outside the scope of this proceeding;
- Is incomplete and fails to justify changes to current, Commission approved practices that are informed by statute; and
- Is impractical in that it requires a customer to choose a generation provider before the customer has committed to interconnecting with PG&E.

If the Commission is inclined to adopt elements of PG&E's proposal, it should only adopt the alternative proposed by CalCCA below.

(a) PG&E's Proposal for Coordination of Service Goes Beyond Information Sharing and is Outside the Scope of this Proceeding

PG&E's coordination of service proposal is driven by PG&E's interests as a bundled procurement provider.[109] While information sharing is an identified issue in the Scoping Ruling, PG&E's proposal goes beyond information sharing and extends instead to the terms and conditions of PG&E's generation service, an issue outside of the scope of this proceeding. To the extent that PG&E believes that it needs clear knowledge of new customers by a certain date, it should make this proposal in a proceeding that has been properly scoped to include PG&E's request for a key term and condition of PG&E's generation service.

Rule 23 currently addresses coordination of service between the CCAs and PG&E. Rule 23 outlines "terms and conditions [that] apply to both Utility customers and CCAs who participate in CCA service."[110] Among other things, Rule 23 covers the terms and conditions applicable to customers who begin electric service in a CCA territory after the CCAs initial mass

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109 Exh. PG&E-04 at 101, lines 20-23.
110 Exh. PG&E-09 at Sheet 1.

enrollment[111] and opt out of CCA service to receive PG&E generation service.[112] PG&E acknowledges that "[a] customer can also opt out to leave CCA service but the customer's departure from CCA service to receive PG&E bundled service is conditioned on the terms in Electric Rule 23." Despite acknowledging that Rule 23 covers departure from CCA service, PG&E has not proposed any changes to Rule 23 in this proceeding.[113] Changes to Rule 23 are squarely outside the scope of this case, and if PG&E believes changes are necessary to account for new large loads, it should propose those changes in a separate application.

(b) PG&E Has Provided an Incomplete Proposal that Fails to Justify Changes to Current, Commission Approved Practices

As presented in testimony, PG&E has provided insufficient evidence to support the proposed changes to current practice. PG&E does not specify whether these changes should be addressed in Rule 23 or in Rule 30, and despite providing a proposed Rule 30 tariff, PG&E has not provided parties with the language that would effectuate the proposed change.[114] Without proposed language, parties are limited in their ability to assess the proposal or how it would interact with practices otherwise.

Additionally, PG&E has not considered how its proposal would interact with current practices under Rule 23, which are informed by statutory requirements. Section 366.2(c)(13) directs that once a customer is automatically "enrolled" with its CCA, the customer has 60 days to opt out of CCA service.[115] While PG&E suggests that a customer should declare its decision

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[111] Exh. PG&E-09 Section K.2 at Sheet 32.

[112] Exh. PG&E-09 Section L at Sheets 33-36.

[113] 3 TR 325:9-14 (PG&E Gutierrez): "Q Are there CCA opt-outs or switching procedures or rules that are not included in Rule 23? A I do not believe so. Q Okay. Does this case propose a change to Rule 23? A It does not."

[114] 3 TRR 328:17-19 (PG&E Gutierrez): "I don't see any proposal on new language that are near or in that coordination of service section."

[115] Section 366.2(c)(13).

to opt out 45 days after the PES is complete, it does not address what would happen if a customer made a decision after that point or how this proposal interacts with Rule 23.[116] Before the Commission can adopt PG&E's proposed changes, a more complete proposal is required. In the absence of a complete proposal, the Commission should reject the coordination of service request.

(c) PG&E's Coordination of Service Proposal Requiring Customers to Choose its Generation Provider Prior to the Transmission Project Being Agreed to Through Execution of an Interconnection Agreement is Impractical and Should be Rejected

Given the agreement upon CCA role as default generation provider, subject to the customer's choice to opt out, PG&E's coordination of service proposal seeks to manage procurement risk by modifying the deadline for CCA opt out. Witness Gutierrez clarified that if a customer elects to take bundled service: "we'll be taking on quite a bit of load for th[ese] customer[s], and our ability to go out and procure it may take some time and that short of a time may not be the best way to do it for customers."[117] PG&E, however, does not have a procurement witness in this proceeding that can attest for what would be required for PG&E to procure for the new large loads.[118] Instead of a supported proposal with justifications for the proposed timeline, PG&E simply proposes a customer determine its generation provider 45 days after the PES report.

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116 3 TR 328:3-10 (PG&E Gutierrez): "Q It had made an election on day 45, but slept on it, and decided to change its mind. A I don't think we have it in the testimony, but I -- I -- I believe, you know, it's in our comfort level to ask for that, and that there may not be that many changes of mind that late in the process. So I think we are hoping that we would get that 45-day notice, and then move along with that."

117 3 TR 327:4-9 (PG&E Gutierrez).

118 3 TR 327: 12-14 (PG&E Gutierrez): "And PG&E does not have a procurement witness in this proceeding. Correct? A I do not believe so, no."

Among other flaws and deficiencies, PG&E's 45-day proposal is also too early in the construction and interconnection process and requires the customer to make decisions while the project may still be uncertain.[119] The PES report is the first real opportunity for the customer to better understand the costs and timing of interconnecting to PG&E's electric system. As described by PG&E in terms of customer deposits: "deposits are for a preliminary study and are only the first step in the interconnection process. As the process proceeds, transmission-level customers must decide whether to enter into an IA and pay upfront the costs for Facility Types 1-3."[120] In other words, the IA is the point at which the customer commits to the project and pays a significant deposit to move forward. The project is more certain only after the IA is signed and deposit paid. There is no set time frame after the PES report for a customer to sign an IA, so the deadline set by PG&E could mean that customers are committing to generation service before they are even committing to interconnecting in California.[121]

At a minimum, any coordination of service proposal should require a customer to commit to generation service only after signing an IA. Considering, "PG&E waits for the customer to execute all required contracts before PG&E proceeds with certain milestones such as equipment procurement and construction,"[122] PG&E is not likely to begin procurement practices before the customer has executed all required contracts. Delaying any coordination of service until after those IAs have been reached should not result in a meaningful delay in potential procurement, but will ensure that the project is more certain.

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[119] Exh. CalCCA-02 at 8, lines 138-139.
[120] Exh. PG&E-04 at 12, lines 18-22.
[121] Exh. CalCCA-02 at 8, line 145 to 9, line 153; Exh. CalCCA-02, Attachment A, Response CalCCA_001- Q005 .
[122] Exh. PG&E-04 at 26, lines 23-26.

(d) If the Commission is Inclined to Consider an Opt-Out Deadline is Required, It Should Occur Only After the Interconnection Agreement and Align with Statutory Enrollment Periods

While coordination of service is outside of the scope of this proceeding, to the extent that the Commission is inclined to address elements of PG&E's coordination of service proposal, any opt-out deadline must be set only after the IA has been signed. As noted above, section 366.2(c)(13) directs that once a customer is automatically "enrolled" with its CCA, the customer has 60 days to opt out of CCA service.[123] Any Commission order for a deadline to commit to either CCA or PG&E service therefore must take into account this statutory requirement. If the Commission decides it must impose a notice requirement, CalCCA proposes the following alternative to PG&E's proposal:

- A new large load customer be considered "enrolled" with the CCA serving its location ninety days after the IA is signed.
- After enrollment, the customer will have sixty days to decide whether to opt out of CCA service. To the extent the customer does not opt out, it will be served by the CCA.
- The customer shall communicate with the CCA and PG&E if it wishes to opt out of CCA service. No action is required on the part of the CCA to communicate this decision to PG&E.
- After the 60 days have passed, the customer may not change its service provider prior to energization.
- Each CCA and PG&E are both able to set the terms and conditions of their service, provided that each requires at least a one-year minimum stay in their service and six-month notice of intent to switch providers.

The Commission should direct PG&E and CalCCA to work together to draft changes to Rule 30 that would effectuate this proposal and would effectively preclude Rule 30 customers from conflicting terms in Rule 23. The new Tariff language should be submitted to the Commission via a Tier 2 Advice Letter for its approval.

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[123] Section 366.2(c)(13).

E. ISSUE 5: Accounting and operational reporting process:

CalCCA takes no position on Issue 5 or its subparts.

1. **Issue 5.a: What accounting and operational reporting requirements are needed to implement Electric Rule 30?**

2. **Issue 5.b: Should PG&E's request to establish a memorandum account to track interest payments for Commission-jurisdictional facilities under Electric Rule 30 be approved?**

3. **Issue 5.c: When seeking to recover amounts in the memorandum account, what accounting requirements should PG&E demonstrate, including (1) paying the appropriate interest rate, (2) paying interest on amounts refunded to the transmission-level customer for facilities included in Commission-jurisdictional rates, and (3) appropriately calculating the interest amount?**

4. **Issue 5.d: Should the requirements of the Commission's Standard Practice U-27-W be required?**

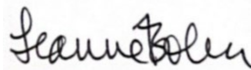
F. Issue 6 – Implementation: Should PG&E be directed to file a Tier 1 AL after a Commission decision is issued in this proceeding directing PG&E to file a revised Electric Rule 30 and form agreements within forty-five (45) days of a final decision?

CalCCA takes no position on Issue 6.

IV. CONCLUSION

CalCCA appreciates the opportunity to submit this Opening Brief and requests the adoption of the positions proposed herein.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

October 24, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes.	R.25-06-019

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON ELECTRICITY PORTFOLIOS FOR 2026-2027 TRANSMISSION PLANNING PROCESS AND NEED FOR ADDITIONAL RELIABILITY PROCUREMENT

Leanne Bober,
Director of Regulatory Affairs and
Deputy General Counsel
Lauren Carr,
Senior Manager, Regulatory Affairs & Market
Policy
Eric Little,
Director of Market Design

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

October 31, 2025

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends the Commission:

- ✓ Focus its efforts on developing RCPPP, as recommended by CalCCA and many parties, as ad hoc procurement orders are not the most effective and efficient mechanism for prompting procurement;
- ✓ Reject ACP-CA's and Hydrostor's comments recommending an increase in the magnitude of procurement as these recommendations deviate from the Commission's needs assessment by introducing assumptions that require further vetting and additional analysis;
- ✓ Exercise caution in determining the need for 2031 and 2032 at the outset given the risk of directing overprocurement, as recognized by Cal Advocates, SDG&E, AReM, and SCE, by adopting CalCCA's proposal for procurement tranches that account for uncertainty - 2,000 MW for Tranche One (2029-2030), and 2,000 MW for Tranche Two (2031-2032), with a needs analysis conducted in 2027 regarding an additional 2,000 MW for 2031-2032 to inform a potential revised needs determination for Tranche Two in Q1 2028;
- ✓ Allocate procurement needs of any potential ad hoc procurement order to all LSEs, as recommended by CalCCA and many other parties, rather than to a CPE;
- ✓ Adopt SCE and SDG&E recommendations for procurement and compliance flexibility to prevent adverse market outcomes described by CLEU, AReM, SCE, and other parties;
- ✓ Reject party recommendations for technology or attribute specific procurement orders, such as LLT, local area, DER, or energy resource specific orders;
- ✓ Reject MGRA's request that the IOUs, CCAs, and ESPs be allocated procurement requirements of 2,000 MW to enable closure of Aliso Canyon; and
- ✓ Further consider the assumptions about EO resources in the context of TPP, procurement, and compliance obligations.

[1] Acronyms used herein are defined in the body of this document.

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON ELECTRICITY PORTFOLIOS FOR 2026-2027 TRANSMISSION PLANNING PROCESS AND NEED FOR ADDITIONAL RELIABILITY PROCUREMENT

California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to the *Administrative Law Judge's Ruling Seeking Comments on Electricity Portfolios for 2026-2027 Transmission Planning Process and Need for Additional Reliability Procurement*[3] (Ruling), dated September 30, 2025.

I. INTRODUCTION

The extensive party Opening Comments[4] present the myriad of challenges associated with a potential near-term ad hoc procurement order such as the one being contemplated by the Ruling. These challenges underscore the critical importance of a programmatic approach to procurement like the one contemplated by the California Public Utilities Commission

[2] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance of Southern California, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[3] *Administrative Law Judge's Ruling Seeking Comments on Electricity Portfolios for 2026-2027 Transmission Planning Process and Need for Additional Reliability Procurement*, Rulemaking (R.) 25-06-019 (Sept. 30, 2025).

[4] All references herein to party Opening Comments are to the Opening Comments filed in this Rulemaking, R.25-06-019, on or about October 22, 2025.

(Commission) with the Reliable and Clean Power Procurement Program (RCPPP). In deciding whether to issue a procurement directive now, the Commission must weigh the impacts of industry changes including the emergence of data centers, changing federal policies, and ongoing technology innovation, along with continued market challenges such as interconnection/transmission delays, supply chain issues, and permitting challenges. The Commission must also consider potential negative market and affordability impacts resulting from such a procurement order. In light of these considerations, CalCCA's Reply Comments respond to eight themes from party Opening Comments.

First, CalCCA agrees with the broad range of stakeholders that encourage the Commission to focus its efforts on completing the development of the RCPPP.[5] RCPPP, as a programmatic approach to procurement, can more effectively address the complex issues associated with procurement than ad hoc procurement orders. As discussed below, ad hoc and unpredictable procurement orders are not the most effective mechanism for bringing new resources online and can markedly drive-up costs for procuring load-serving entities (LSE) and their customers at a time when customer affordability continues to be a significant challenge. The Commission and stakeholders are also in the process of contemplating how RCPPP can address complex issues, such as needs allocation considering the question of who is causing the need for new resources which should then obligate that entity to procure for those needs. These issues cannot be adequately resolved within an ad hoc procurement order. The Commission should therefore establish RCPPP as its highest priority within the IRP proceeding.

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[5] *See* Alliance for Retail Energy Markets (AReM) Opening Comments, at 21; California Coalition of Large Energy Users (CLEU) Opening Comments, at 10-11; Natural Resources Defense Council Opening Comments (NRDC), at 4; Shell Energy North America (US), L.P. (Shell) Opening Comments, at 2; and Western Power Trading Forum (WPTF) Opening Comments, at 2.

Second, the Commission should reject recommendations by American Clean Power-California (ACP-CA) and Hydrostor, Inc. (Hydrostor) to increase the required procurement beyond 6,000 megawatts (MW) based upon untested assumptions about import availability and data center load growth. Instead, the Commission should: (1) further study the import assumptions to determine if modifications are necessary; and (2) order any procurement in two tranches – 2,000 MW for Tranche One (2029-2030), and 2,000 MW for Tranche Two (2031-2032), and update the needs analysis in 2027 regarding an additional 2,000 MW for 2031-2032 to inform a potential revision for Tranche Two in the first quarter (Q1) 2028.

Third, CalCCA agrees with Opening Comments of AReM, Southern California Edison Company (SCE), the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), and San Diego Gas & Electric Company (SDG&E) urging caution in establishing procurement requirements, especially for 2031 and 2032, given the many extenuating circumstances that could impact the needs in those later years. CalCCA agrees it is premature to determine whether the total need put forth by the Commission is accurate, which drives CalCCA's proposal that if the Commission orders procurement, it should order procurement in tranches with lower amounts until needs can be reassessed with greater load forecast certainty.

Fourth, CalCCA agrees with the many parties who recommend individual LSE procurement rather than central procurement.[6] Central procurement has not proven to be more successful or efficient than individual LSE procurement and has the potential to increase costs and disrupt the market at a time when LSEs are already conducting procurement to meet a variety of needs. The Commission should therefore reject recommendations for central

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6 *See* Pacific Gas & Electric Company (PG&E) Opening Comments, at 27-29; Middle River Power, LLC (MRP), Opening Comments, at 11-12; Mussey Grade Road Alliance (MGRA) Opening Comments, at 10-11; SCE Opening Comments, at 22-24; SDG&E Opening Comments, at 20; and Shell Opening Comments, at 11-14, 16.

procurement.[7] However, if the Commission chooses to include a central procurement element, any central procurement should be strictly voluntary. In other words, those LSEs who prefer to have a central procurement entity (CPE) procure on their behalf would opt-in to have their needs covered by a CPE.

Fifth, many parties' Opening Comments, including those from the California Coalition of Large Energy Users (CLEU), AReM, and SCE, describe the adverse market outcomes and potential cost implications of ad hoc procurement orders. CalCCA agrees with these positions, as described more fully in CalCCA's Opening Comments. The Commission should adopt SCE's and SDG&E's recommendations to provide LSEs with procurement and compliance flexibility to ensure LSEs can conduct procurement in a cost-effective manner.

Sixth, if the Commission issues a procurement order, it should not adopt party recommendations for technology or attribute specific procurement orders such as an order for long-lead time (LLT), local area, distributed energy resources (DER), or energy resources.[8] Increasing demand for procurement to meet aggressive timelines may put upward pressure on prices for resources, especially for scarce technologies. Therefore, should the Commission issue a procurement order, it should do so for generic capacity only.

Seventh, the Commission should reject MGRA's misguided request that the investor-owned utilities (IOU), CCAs, and ESPs be responsible for annually procuring 2,000 MW to

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[7] ACP-CA Opening Comments, at 35; AReM Opening Comments, at 8; and Hydrostor Opening Comments, at 3, 24-25.

[8] California Environmental Justice Alliance (CEJA)/Sierra Club Opening Comments, at 35-37; CLEU Opening Comments, at 20-21; ENGIE North America Inc. (ENGIE) Opening Comments, at 4-5; Environmental Defense Fund (EDF) Opening Comments, at 11-14, 15-16; Fervo Energy Company (Fervo) Opening Comments, at 14-15; Form Energy, Inc. (Form) Opening Comments, at 10 (alternative proposal); GreenGen Storage, LLC (GreenGen), Opening Comments, at 14; Hydrostor Opening Comments, at 20-23; Solar Energy Industries Association and the Large-scale Solar Association (LSA/SEIA) Opening Comments, at 18; Vote Solar Opening Comments, at 9; and Southern California Gas Company (SoCalGas) Opening Comments, at 1-3.

account for the Alison Canyon closure. Neither Investigation (I.) 17-02-002 nor this proceeding has determined a need for resources associated with the reduction in use of Aliso Canyon. The Commission must first assess the need for additional resources to reduce reliance on Aliso Canyon and allow stakeholders to comment on that need before issuing a procurement order for that purpose.

Eighth, party comments demonstrate the need to further consider the role that energy only (EO) resources will play in driving transmission planning and meeting reliability needs. For the reasons described herein, the Commission should: (1) adopt party recommendations that would enhance the busbar mapping process' ability to identify when upgrades are needed in areas without existing or planning deliverability; and (2) adopt the California Wind Energy Association's (CalWEA) recommendation to consider allowing EO resources to meet any interim procurement order resulting from the ruling, while avoiding conflicts with other compliance obligations.[9]

As set forth below, CalCCA respectfully requests the Commission:

- ✓ Focus its efforts on developing RCPPP, as recommended by CalCCA and many parties, as ad hoc procurement orders are not the most effective and efficient mechanism for prompting procurement;
- ✓ Reject ACP-CA's and Hydrostor's comments recommending an increase in the magnitude of procurement as these recommendations deviate from the Commission's needs assessment by introducing assumptions that require further vetting and additional analysis;
- ✓ Exercise caution in determining the need for 2031 and 2032 at the outset given the risk of directing overprocurement, as recognized by Cal Advocates, SDG&E, AReM, and SCE, by adopting CalCCA's proposal for procurement tranches that account for uncertainty - 2,000 MW for Tranche One (2029-2030), and 2,000 MW for Tranche Two (2031-2032), with a needs analysis conducted in 2027 regarding an additional 2,000 MW for 2031-2032 to inform a potential revised needs determination for Tranche Two in Q1 2028;

[9] CalWEA Opening Comments, at 15.

- ✓ Allocate procurement needs of any potential ad hoc procurement order to all LSEs, as recommended by CalCCA and many other parties, rather than to a CPE;
- ✓ Adopt SCE and SDG&E recommendations for procurement and compliance flexibility to prevent adverse market outcomes described by CLEU, AReM, SCE, and other parties;
- ✓ Reject party recommendations for technology or attribute specific procurement orders, such as LLT, local area, DER, or energy resource specific orders;
- ✓ Reject MGRA's request that the IOUs, CCAs, and electric service providers (ESP) be allocated procurement requirements of 2,000 MW to enable closure of Aliso Canyon; and
- ✓ Further consider the assumptions about EO resources in the context of the Transmission Planning Process (TPP), procurement, and compliance obligations.

II. THE DEVELOPMENT OF RCPPP SHOULD BE PRIORITIZED, AS SUPPORTED BY MANY PARTIES

CalCCA agrees with the broad range of stakeholders that recommend the Commission focus its efforts on completing the development of the RCPPP framework.[10] Ad hoc procurement orders are not the most effective method to spur procurement and can cause significant market disruptions that increase procurement costs and exacerbate affordability issues.[11] Ad hoc procurement orders can take negotiating power away from LSEs and result in riskier contract provisions to enable LSEs to meet their compliance obligations under aggressive timelines and with exorbitant costs. As stated by CLEU, any ad hoc procurement order should be "constructed narrowly in order to provide a

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[10] *See* AReM Opening Comments, at 21; CLEU Opening Comments, at 10-11; NRDC Opening Comments, at 4; Shell Opening Comments, at 2; and WPTF Opening Comments, at 2.

[11] *See* CalCCA Opening Comments, at 4-5 and 25-26. Economic theory predicts that increases in demand are met by increases in price. If the order is beyond the needs of LSEs, the demand will increase in total. In addition, there is a temporal consideration in which LSEs may not have gone to market at that moment in time, while an order will force such action. Finally, ad hoc orders carry with them penalty mechanisms which can inform sellers of opportunity costs which will enable them to determine pricing. This can happen because the field of resources that could meet the need in the timeframe suggested by this order is limited which will limit the amount of competition from suppliers.

stopgap until a durable RCPPP is adopted and implemented," and the Commission should "return its focus to adopting a durable midterm reliability framework in the RCPPP."[12]

Among issues with ad hoc procurement orders that the RCPPP can address is how to identify the entity or entities responsible for the development of new resources. In response to Question 13, AReM presumes that without lifting the cap on direct access, it is not the ESPs' load that is contributing to a need for new resources. Specifically, AReM states, "[w]ith the cap in place, it is unjust and inequitable for ESPs to be forced to contract for new generation resources needed to serve customers of other LSEs."[13] AReM further states:

> "[t]he Ruling is clear that the large amount of load growth in the 2024 IEPR, including and especially from interconnecting new data centers, is the single most important driver of the procurement need. However, with the current cap on the DA program, ESPs are not legally capable of serving this load growth. This inequity will create significant challenges for all DA service providers in California by widening the competitive gap between ESPs whose load is capped and LSEs that can continue to expand their customer base."[14]

Shell raises similar issues in its comments.[15]

Fundamentally, AReM and Shell raise the question of who is causing the need for new resources that should obligate that entity to procure for that need. This issue extends more broadly beyond the direct access cap. Other LSEs are not seeking to increase the load that they serve and may not have data centers coming to their service areas. In addition, while data center growth is a large element of the need for new resources, it is not the only driver of need now or in the future. Clean energy needs, resource retirements, and the changing mix of resources on the grid will all have impacts on new resource procurement needs. Attempting to carve out specific

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12 CLEU Opening Comments, at 14 and 25.
13 AReM Opening Comments, at 10.
14 *Id.* at 14.
15 *See* Shell Opening Comments, at 8-11.

portions of ad hoc procurement orders to specific LSEs based on needs other than peak load is likely prohibitively complex given the usual short timeframe to arrive at an order that leaves sufficient time for LSEs to procure.

RCPPP is considering all these factors and includes a proposal to address reliability needs allocation by setting obligations for existing and new resources, with adequate time to procure cost-effectively in advance, to ensure the total mix of resources meets total reliability needs. In addition, there is discussion of how meeting SB 100[16] goals for clean energy will be met by all LSEs to ensure that the LSEs are individually responsible for their share of clean energy to meet their loads. RCPPP, as a programmatic approach to procurement, can address the equity concerns raised by AReM and Shell. Given the ongoing work to consider these and other complex issues within RCPPP, the Commission should prioritize the development of RCPPP.

III. ACP-CA AND HYDROSTOR'S RECOMMENDATIONS FOR PROCUREMENT BEYOND 6,000 MW BASED ON PREMATURE ASSUMPTIONS ABOUT IMPORT AVAILABILITY AND DATA CENTER LOAD GROWTH SHOULD BE REJECTED

ACP-CA's and Hydrostor's recommendations that the Commission consider increasing the magnitude of the procurement order deviate from the Commission's needs assessment by introducing assumptions that require further vetting and additional analysis.[17] For example, ACP-CA states the Commission's needs assessment represents a "lower bookend" of need, basing its assumption primarily on the assertion that the Commission's portfolio of resources relies too heavily on unspecified and uncontracted imports "unlikely to be available when needed in the coming years."[18] ACP-CA recommends reducing or eliminating assumed availability of

16 Senate Bill 100 (SB 100) (De León, Ch. 312, Stats. 2018).
17 *See* ACP-CA Opening Comments, at 27; and Hydrostor Opening Comments, at 6.
18 ACP-CA Opening Comments, at 24-25.

unspecified/uncontracted imports given projected supply and demand imbalances in the West and the forthcoming implementation of the Western Resource Adequacy Program (WRAP).[19]

CalCCA acknowledges that the potential for supply and demand imbalances in the West could impede California's ability to depend on imports for reliability,[20] and recognizes that import assumptions should be revisited in this context. However, it is premature to base a procurement order on evolving capacity dynamics of the rest of the West until the Commission has fully analyzed and vetted potential adjustments to the import assumptions. Indeed, AReM has questioned whether the import assumptions are too low, and has advised against "arbitrary assumptions in favor of one based on rigorous analysis of the level of imports likely to be available from neighboring regions."[21] In addition, once the full extent of WRAP participation is known on October 31, 2025,[22] the Commission and stakeholders will have an opportunity to better assess whether potential changes to the import assumptions are warranted.

In addition, Hydrostor recommends additional procurement in part because "data center load may be understated."[23] As described extensively in CalCCA's Opening Comments, large load and electrification forecasting uncertainties should inform a cautious approach to the Commission's procurement recommendations, as the magnitude of some data center interconnection requests and uncertainties related to a data center's actual peak load could

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[19] *See id.*, at 7, 13.

[20] *Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results* (Sept. 22, 2025): https://apiproxy.utc.wa.gov/cases/GetDocument?docID=91&year=2021&docketNumber=210096: ("Accelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to 9 GW by 2030.")

[21] AReM Opening Comments, at 4.

[22] Robert Mullin, *WPP Board Declines to Delay WRAP 'Binding' Phase Commitment Deadline* (Oct. 9, 2025): https://www.rtoinsider.com/116828-wpp-board-declines-delay-wrap-binding-phase-commitment-deadline/#:~:text=NV%20Energy%20has%20already%20notified,the%20WRAP%20and%20its%20participants.

[23] Hydrostor Opening Comments, at 6.

materially impact the forecast.[24] Numerous stakeholders agree with CalCCA that there is significant uncertainty around data center loads,[25] and recommend the Commission base any procurement order on the "reduced load from electrification and data centers" sensitivity as being more realistic.[26] For these reasons, the Commission should not increase the magnitude of its recommended procurement order, and instead take the cautious and flexible approach described below.

IV. CALCCA'S RECOMMENDATION OF PROCUREMENT TRANCHES BASED ONLY ON IDENTIFIED NEED ADDRESS PARTY COMMENTS URGING THE COMMISSION TO PROCEED CAUTIOUSLY IN ORDERING PROCUREMENT FOR 2031 AND 2032

CalCCA's recommendation for procurement tranches based only on identified need align with party recommendations that the Commission proceed cautiously with ordering procurement for 2031 and 2032. As set forth below, limiting the procurement order to immediate needs in 2029 and 2030 will allow the Commission to evaluate Effective Load Carrying Capacity (ELCC) values to determine if the total need across 2029 through 2032 is feasible and commercially available,[27] and prevent over-procurement negatively impacting affordability, as recommended by AReM and SCE. CalCCA also agrees with Cal Advocates and SDG&E that it is premature to determine whether the total need put forth by the Commission is accurate, resulting in CalCCA's Opening Comments recommending an initial need determination of a lower amount until needs

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24 CalCCA Opening Comments, at 8-17.

25 CEJA/Sierra Club Opening Comments, at 11-12; SDG&E Opening Comments, at 9; and Shell Opening Comments, at 4-5.

26 AReM Opening Comments, at 3-4; Calpine Corporation (Calpine) Opening Comments, at 6; and WPTF Opening Comments, at 6.

27 CalCCA continues to support using SOD accounting for any interim procurement order resulting from this Ruling. If, however, the Commission moves forward with the Ruling's recommendation to use ELCC accounting, the Commission must carefully evaluate the feasibility and commercial availability of resource procurement in the context of the ELCC values.

can be reassessed with better information. CalCCA therefore continues to recommend that if the Commission orders procurement, it should: (1) further study the import assumptions as discussed in Section III. above, to determine if modifications are necessary; and (2) order procurement in two tranches – 2,000 MW for Tranche One (2029-2030), and 2,000 MW for Tranche Two (2031-2032), with a needs analysis conducted in 2027 regarding an additional 2,000 MW for 2031-2032 to inform a potential revised needs determination for Tranche Two in Q1 2028.

A. Reassessing 2031 and 2032 Needs Will Allow the Commission to Assess the Feasibility of any Procurement Order and Validate that the Magnitude Realistically Reflects System Need

Limiting the procurement order to immediate needs in 2029 and 2030 will allow the Commission to evaluate ELCCs to determine if the total need across 2029 through 2032 is feasible and commercially available. AReM notes that an order for 6,000 MW of net qualifying capacity (NQC) may actually be equivalent to 40,000 MW of nameplate capacity from 4-hour storage due to declining ELCC values.[28] CalCCA shares the concern that the level of new resource development to provide 6,000 MW of NQC by 2032 may not be feasible or commercially available. Because the existing base of installed and contracted solar and storage is expected to exceed 50 gigawatts by 2028, the marginal reliability contribution of more solar and 4-hour storage is dramatically reduced by 2032. Over 90 percent of the projects in the interconnection queue with proposed online dates between 2029-2032 are solar and/or storage.[29] CalCCA's SOD RA Stack analysis shows that eliminating gaps between resource adequacy (RA) supply and demand in all hours of a September peak day in 2032 requires approximately 16,000 MW of solar and 16,000 MW of 4-hour storage, if all the gap is to be met by those resources.

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28 AReM Opening Comments, at 9.

29 CalCCA analysis of data from Berkeley Lab. "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection" Queued Up 2025 Data File available at: https://emp.lbl.gov/sites/default/files/2025-08/LBNL_Ix_Queue_Data_File_thru2024_v2.xlsx.

Validating that such a scale of market development is prudent prior to committing LSEs to make this level of investment based on an uncertain load forecast.

CalCCA agrees with SCE's caution regarding potential overprocurement and the impact on customer affordability. SCE states that:

> [t]o protect customer affordability, it is essential that any procurement order be based on a realistic assessment of actual system need. Overestimating procurement requirements (e.g., by applying RCPPP Staff Proposal ELCC values) can exacerbate upward price pressure and result in unnecessary costs to customers."[30]

Therefore, reassessing 2031 and 2032 needs prior to ordering additional procurement will allow the Commission to validate that the requirements realistically reflect system need, or to adjust the later year requirements if they do not.

B. Cal Advocates' and SDG&E's Recommendations to Refrain from Ordering Procurement for 2031 and 2032 Should be Adopted with Procurement Tranches that Allow for a Needs Reassessment for 2031 and 2032

CalCCA agrees with Cal Advocates and SDG&E that it is premature to lock in procurement requirements for 2031 and 2032 at this time. Cal Advocates states that waiting to issue procurement orders for 2031 and 2032 would allow for "new and better information" to inform the need, including the pace of mid-term load growth, the status of DCPP, new individual LSE IRPs, effects of LSE procurement on ELCCs, the status of LLT project delays, RCPPP design and implementation, and DWR procurement volumes and attributes.[31] Likewise, SDG&E recommends the Commission refrain from ordering procurement for 2031 and 2032 given "[t]here is significant uncertainty about longer-term IEPR load forecasts given the abrupt change from the 2023 IEPR to the 2024 IEPR with the addition of forecasted data center load."[32]

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[30] SCE Opening Comments, at 15.
[31] *See* Cal Advocates Opening Comments, at 7-8.
[32] SDG&E Opening Comments, at 9.

The Commission should instead adopt lower requirements at the outset and commit to re-evaluating the 2031-2032 procurement need in mid to late 2027, closer to the need materializing. This will allow the Commission to use the most current information to inform the magnitude of any procurement order and ensure any procurement ordered is sufficient to meet reliability needs, while not resulting in over-procurement at a detriment to ratepayers.

As stated above, the Commission should prioritize the development of RCPPP to replace ad hoc procurement orders. The Commission should therefore seek to implement the RCPPP in time to address any needs revealed for 2031-2032. If the Commission determines it cannot implement RCPPP in time, the Commission should allocate any procurement requirements for 2031-2032, if needed, by Q1 2028.

Specifically, the Commission should order any procurement in two tranches – 2,000 MW for Tranche One (2029-2030), and 2,000 MW for Tranche Two (2031-2032), with a needs analysis conducted in 2027 regarding an additional 2,000 MW for 2031-2032 to inform a potential revised needs determination for Tranche Two in Q1 2028. This approach will provide the Commission the ability to reassess later-year needs with more current information *and* provide LSEs the flexibility to comply in tranches rather than over precise yearly dates.

V. PROCUREMENT NEEDS SHOULD BE ALLOCATED TO ALL LSES, AS RECOMMENDED BY MANY PARTIES, RATHER THAN TO A CENTRAL PROCUREMENT ENTITY

CalCCA agrees with Calpine, Form, PG&E, MGRA, MRP, SCE, SDG&E, and Shell, who all recommend that any procurement order resulting from the Ruling be issued to all LSEs rather than to a CPE.[33] As stated by MRP, "[i]ndividual LSEs are in the best position to know

[33] *See* Calpine Opening Comments, at 8; Form Opening Comments, at 10-11; PG&E Opening Comments, at 27-29; MGRA Opening Comments, at 10-11; MRP Opening Comments, at 11-12; SCE Opening Comments, at 22-24; SDG&E Opening Comments, at 20; and Shell Opening Comments, at 14.

how much and what kind of capacity meets their own customers' needs. The Commission has recognized LSE procurement autonomy as important and therefore should only utilize a [CPE] as a last resort."[34] Further, central procurement "eliminates the ability of LSEs to react to the individual needs of their communities. It limits the ability of CCAs to procure on behalf of their customers, which is required by state law."[35]

CalCCA also agrees with Shell, who states that "central procurement has not been shown to reduce costs or improve reliability."[36] As recognized by SCE, LSEs are already in the market procuring for a variety of needs, and:

> The addition of a CPE such as the IOUs or the Department of Water Resources procuring a large amount of new capacity on behalf of all LSEs would likely contribute to upward pressure on prices for the limited resources available, negating any perceived efficiencies associated with procuring at scale. The use of a CPE also complicates implementation and cost recovery and may hinder efforts already underway by LSEs. Central procurement may also lead to overprocurement and unnecessary costs to customers because it may not take into account the procurement underway by LSEs, particularly for near-term procurement to take advantage of federal tax credits.[37]

For all of these reasons, the Commission should reject party recommendations for central procurement.

On the other hand, CalCCA disagrees with parties urging the Commission to order a CPE to conduct procurement. Hydrostor states that "[t]he procurement should ideally be conducted by a [CPE], such as sophisticated LSE, capable of immediately initiating such procurement before year's end considering the quickly approaching deadlines for ensuring clean energy projects will

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[34] MRP Opening Comments, at 11-12 (footnote omitted).
[35] MGRA Opening Comments, at 10.
[36] Shell Opening Comments, at 11.
[37] SCE Opening Comments, at 23.

receive federal incentives and tax credits."[38] However, LSEs have open RFOs for resources eligible for federal incentives and tax credits.[39] Adding a CPE to the mix would disrupt these ongoing efforts. As stated by PG&E:

> allocating procurement responsibility to the IOUs on behalf of all other LSEs is likely to disturb on-going procurement activities (some of which may be in the mid-to-late stages of contract negotiations and executions) by the IOUs and all other LSEs and create a distraction as all LSEs will be forced to digest another set of rules and deadlines under a new centralized procurement framework, potentially delaying the timing of this procurement order."[40]

Furthermore, in an attempt to circumvent the credible reasons[41] for further vetting of the IEPR load forecast and its treatment of uncertain large loads, ACP-CA states that it:

> [R]recognizes that there have been considerable objections from some LSEs regarding the need to plan for the adopted IEPR load forecast. To the extent LSEs are unwilling or unable to self-procure resources necessary to meet anticipated loads, ACP-California would support central procurement, by DWR or by the IOUs, as a non-preferred alternative to LSE-led procurement."[42]

Despite ACP-CA's assertions, calling for more a cautious approach to determining procurement needs resulting from large loads until a transparent and accurate process is established for incorporating large loads into the forecast does not translate to an unwillingness or inability to self-procure. CCAs have demonstrated that they are willing and able to self-procure resources to meet their customers' needs.[43] A rush to order procurement for speculative load could result in

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[38] Hydrostor Opening Comments, at 3.

[39] *See, e.g.,* CC Power, *Request for Proposals for Clean Generation and Capacity Resources*: https://cacommunitypower.org/solicitations/. ("…CC Power is interested in a range of projects for potential ownership, leveraging the benefits of the Inflation Reduction Act. Further, CC Power is seeking projects that can retain ITC eligibility by meeting the start of construction guidelines in the One Big Beautiful Bill Act (O3BA).")

[40] PG&E Opening Comments, at 28.

[41] CalCCA Opening Comments, at 8-17.

[42] ACP-CA Opening Comments, at 35 (footnote omitted).

[43] CalCCA Opening Comments, at 4-5, 44.

LSEs spending considerable amounts on generation at the expense of customers for loads that do not materialize. Instead, the Commission should define the procurement need considering uncertainty by adopting procurement tranches, reevaluating the need in the later tranche as more information is certain, as described above, and allocating that need to all LSEs.

Finally, AReM states that it "is not convinced there is a need for procurement of new resources to support reliability in the 2028-2032 timeframe," but if the Commission nonetheless moves forward with a procurement order, AReM favors central procurement by the IOUs.[44] CalCCA strongly favors procurement by individual LSEs. However, if the Commission chooses to include a central procurement element, any central procurement should be strictly voluntary, as recommended by GreenGen,[45] in which those LSEs who prefer to have a CPE procurement on their behalf could voluntarily elect to have their needs covered by a CPE.

VI. SCE AND SDG&E'S RECOMMENDATIONS FOR FLEXIBILITY TO PREVENT ADVERSE MARKET IMPACTS IDENTIFIED BY PARTIES SHOULD BE ADOPTED

The Commission should adopt recommendations by SCE and SDG&E for flexibility associated with any procurement order to counter potential adverse market impacts resulting from such an order. Procurement orders, particularly those under a compressed timeline, can contribute to significant market distortions and ultimately impact customer affordability. Adding known amounts of demand at the same time with known financial consequences that are unavoidable provide information to sellers regarding their pricing. This is particularly problematic when the timeframe for procurement will limit the number of sellers that could meet the need. Allowing flexible compliance will mitigate to some extent the ability of sellers to use

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44 AReM Opening Comments, at 10.

45 *See* GreenGen Opening Comments, at 15.

known financial consequences as an upper bound to their pricing. SCE's Opening Comments note the impacts of such an order:

> "Increasing demand, especially under a compressed procurement timeline, may drive up prices for resources such as energy storage and clean energy generation capacity. Recent procurement cycles have demonstrated that when the Commission issues orders with aggressive timelines, developers respond by raising offer prices to account for increased risks related to interconnection schedule, supply chain and engineering procurement construction constraints, and accelerated project permitting and development. For example, the market responded to the MTR procurement orders with significant increases in bid prices for battery energy storage systems.[46]

SCE also highlights "the challenging market conditions for procuring clean energy resources, including the accelerated phase-out and modification of federal tax credits, tariff policy uncertainty, interconnection queue and permitting delays, and the modification of the requirements for permitting on federal lands."[47] Similar comments were made by CLEU and AReM,[48] both of which conclude that the Commission should require a central buyer to combat the potential exercise of market power by sellers.[49] Further, Shell highlights that even centralized procurement has been unsuccessful in bringing down costs in a distorted market.[50]

As a result of the potential market impacts of the procurement order, as well as continued delays in bringing projects to commercial operation, the Commission should adopt SCE's and SDG&E's recommendations for flexible and alternate compliance methods to protect customer affordability. *First,* the Commission should adopt SCE's recommendation to allow the "alternative compliance pathway adopted for MTR procurement in D.25-09-007 for any new

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46 SCE Opening Comments, at 15.

47 *Id.* at 3.

48 CLEU Opening Comments, at 2-11; and AReM Opening Comments, at 8-9.

49 *See* CLEU Opening Comments, at 2-11, 18-19; AReM Opening Comments, at 7, 8-9; *see also* SDG&E Opening Comments, at 11-12; and MRP Opening Comments, at 3-4.

50 Shell Opening Comments, at 11-14.

procurement ordered in response to this Ruling, which will allow LSEs to address delays that occur for reasons outside LSEs' control despite LSEs' good faith efforts to meet their procurement requirements."[51] Specifically, the Commission should extend the alternative compliance method of allowing LSEs to remain in compliance with their MTR and D.23-02-040[52] (as modified by D.24-02-047) procurement obligations if they can show that they have executed contracts to meet the obligations and have met their month-ahead system RA obligations for the months in which their procurement was delayed.[53]

Second, the Commission should adopt SDG&E's recommendation to allow waivers or extensions under circumstances in which the LSE has made good faith efforts to comply but cannot due to circumstances outside of the LSEs' control. SDG&E states that:

> it is important that the Commission adopt a robust waiver or extension process similar to the [LLT] process established in the MTR procurement decision and allow LSEs to avoid penalties if they make a good faith effort to procure but are unable to satisfy the procurement obligation for reasons outside of their control."[54]

Allowing waivers when LSEs have made good faith efforts to comply will help to mitigate the exercise of market power as well as not penalizing for unavoidable circumstances.

VII. PARTY RECOMMENDATIONS FOR TECHNOLOGY OR ATTRIBUTE SPECIFIC PROCUREMENT ORDERS SHOULD BE REJECTED

Party recommendations for technology or attribute specific procurement orders, such as placing minimum requirements on LLT, local area, DER, or energy resource specific orders,

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[51] SCE Opening Comments, at 16.

[52] Decision (D.) 23-02-040, *Decision Ordering Supplemental Mid-Term Reliability Procurement (2026- 2027) and Transmitting Electric Resource Portfolios to California Independent System Operator for 2023-2024 Transmission Planning Process*, R.20-05-003 (Feb. 28, 2023).

[53] D.25-09-007, *Decision Granting, with Modifications, Southern California Edison Company's Petition for Modification of Decisions 23-02-040 and 24-02-047*, R.20-05-003 (Sept. 26, 2025), Ordering Paragraph 6, at 45-46.

[54] SDG&E Opening Comments, at 11-12.

should be rejected.[55] As discussed in section V. above, the market for procuring resources in short timeframes creates difficulty for buyers and the potential for market power. Placing further constraints on procurement will only serve to make procurement more expensive, impacting customer affordability.

This issue is particularly problematic when there are other considerations and alternatives that should be considered such as in the case of local area resources and DERs. With local area resources, a combination of issues make uncertain whether the procurement will effectively meet needs. For example, the CAISO has informed how battery storage can be located in a local area, but this location may not be effective due to the inability of the local resources and transmission system to fully charge those batteries.[56] Without considering these constraints, providing a procurement order for local area resources cannot be effectively implemented. In addition, local area needs can either be met by generation in the constrained area or by developing transmission to alleviate the constraints. Without an assessment of the most cost-effective combination of resources and transmission improvements to address the local needs, an order for local area resources is premature.

Instead, before contemplating any form of local resource procurement obligation, the Commission should work with the CAISO to identify the types and quantities of resources along with their location to provide a meaningful value in serving local area needs. In addition, the Commission and CAISO should determine if the most cost-effective way to address local needs

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[55] CEJA/Sierra Club Opening Comments, at 35-37; CLEU Opening Comments, at 20-21; ENGIE Opening Comments, at 4-5; EDF Opening Comments, at 11-14, 15-16; CEC Opening Comments, at 13; Fervo Opening Comments, at 14-15; Form Opening Comments, at 10 (alternative proposal); GreenGen Opening Comments, at 14; Hydrostor Opening Comments, at 20-23; LSA/SEIA Opening Comments, at 18; Vote Solar Opening Comments, at 9; and SoCalGas Opening Comments, at 1-3.

[56] *CAISO*, 2026 Local Capacity Technical Study, (Dec. 2, 2024), at 13-14: https://stakeholdercenter.caiso.com/InitiativeDocuments/FinalStudyManual-2026LocalCapacityRequirements.pdf.

is through new resources or through improvements to the transmission system serving the local area. These efforts cannot be completed in time for this interim procurement order, and should instead be addressed through the IRP and Transmission Planning Process to arrive at the least-cost solution for consumers.

With respect to DERs, these resources can and ultimately should provide a solution to meet the procurement needs, including those defined in this interim procurement order. However, they should not be specified to have a minimum procurement obligation. The Commission continues to develop rules concerning DERs. Without certainty of how DERs will be counted toward meeting multiple reliability objectives including this interim order and RA, however, mandating a minimum quantity of DERs is likely to result in sub-optimal procurement. Instead of ordering a minimum quantity, the Commission should instead continue to evolve the DER rules so that future procurement of those resources will have known benefits. This will enable buyers to fully evaluate the costs and benefits, and enable them to optimize, such procurement.

Finally, some commentors recommend that the Commission specify requirements for LLT or clean energy.[57] While these procurement categories are important and do deserve the attention of the Commission, they should be part of the RCPPP discussion and not specifically required through an interim order. Several parties, including AReM, Hydrostor, REV Renewables, SCE, and SDG&E, describe how the RA program's SOD framework requires LSEs to show sufficient energy to change battery storage resources, so it is unnecessary for an IRP procurement order to account for this issue.[58] Further, the RCPPP is determining how to meet

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[57] *See* CRC Opening Comments, at 13; EDF Opening Comments, at 11-14; Fervo Opening Comments, at 14-15; Form Opening Comments, at 10 (in their alternative proposal); GreenGen Opening Comments, at 14; Hydrostor Opening Comments, at 20-23; and SoCalGas Opening Comments, at 1-3.

[58] See AReM Opening Comments, at 10-11; Hydrostor Opening Comments, at 18-19; REV Renewables, LLC (REV Renewables), Opening Comments, at 7; SCE Opening Comments, at 17; and SDG&E Opening Comments, at 14.

SB 100 goals beyond the current RPS requirements. Without understanding which resources will count and how they will count in that program, requirements in this interim order are speculative. In addition, LSEs are under RPS obligations and will seek to optimize their procurement in this interim order with any obligation for renewable resources. CCAs prefer clean energy resources and will continue to procure them. Having more certainty on how and which resources (*e.g.,* large hydro, carbon capture and storage, or other innovative technologies) will count is necessary, rather than a procurement order for specific technologies and/or attributes.

VIII. MUSSEY GRADE ROAD ALLIANCE'S REQUEST THAT THE IOUS, CCAS, AND ESPS BE ALLOCATED PROCUREMENT REQUIREMENTS OF 2,000 MW TO ENABLE CLOSURE OF ALISO CANYON SHOULD BE REJECTED

The Commission should reject MGRA's misguided request that the IOUs, CCAs, and ESPs be responsible for annually procuring 2,000 MW to account for the Alison Canyon closure as a result of their comments in the Aliso Canyon rulemaking, I.17-02-002, urging the Commission to focus procurement issues in the IRP proceeding. MGRA states:

> Because PG&E, SCE, SDG&E, the CCAs, and a representative of numerous independent energy producers each recommended procurement in the IRP proceeding to enable closure of Aliso Canyon, MGRA recommends that these entities be ordered to annually procure 2,000 MWs of non-GHG-emitting NQC toward the closure of Aliso Canyon. The allocation of procurement percentage to each LSE should be based on each LSE's share of the managed peak on the electric system as of the resource adequacy program year 2026, just like is proposed for other allocation purposes in the Ruling.[59]

MGRA mispresents the comments made in the Aliso Canyon proceeding by CalCCA. Specifically, CalCCA did not agree that 2,000 MW of generation was needed to enable the reduced reliance on Aliso Canyon to produce electricity. Rather, CalCCA recommended that any Aliso Canyon needs be considered *within a procurement proceeding where all needs could be*

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[59] MGRA Opening Comments, at 9.

evaluated at once, like in the IRP.[60] Neither I.17-02-002 nor this proceeding has determined a need for resources associated with the reduction in use of Aliso Canyon. If the Commission wishes to examine the need for non-emitting resources to reduce reliance on Aliso Canyon for electricity production, it must first assess the need and allow stakeholders to comment on that need before issuing a procurement order for that purpose.

IX. FURTHER CONSIDERATION OF TREATMENT OF EO RESOURCES IN THE CONTEXT OF TPP, PROCUREMENT, AND COMPLIANCE OBLIGATIONS IS NECESSARY

Party comments demonstrate the need to further consider the role EO resources will play in driving transmission planning and meeting reliability needs. For the reasons described below, the Commission should: (1) adopt party recommendations that would enhance the busbar mapping process' ability to identify when upgrades are needed in areas without existing or planning deliverability; and (2) the Commission should consider allowing EO resources to meet any interim procurement order resulting from the ruling, as recommended by CalWEA, while avoiding conflicts with other compliance obligations.

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[60] *See California Community Choice Association's Comments on the Proposed Decision Adopting Biennial Assessment Process,* Investigation (I.) 17-02-002 (Dec. 3, 2024), at 1-3 (stating that the Commission should defer any procurement of non-gas fired generation needed to reduce reliance on Alisa Canyon to a procurement-related proceeding, including IRP and through the RCPPP, to meet reliability and clean energy resource needs); *see also Opening Comments of Southern California Edison Company (U 338-E) on the Proposed Decision of ALJ Zhang Adopting Biennial Assessment Process,* I.17-02-002 (Dec. 3, 2024), at 2.

A. Party Recommendations to Enhance the Busbar Mapping Process' Ability to Identify Upgrades in Areas without Existing or Planning Deliverability Should be Adopted

CalCCA shares party concerns around the potential for the CAISO's new interconnection intake process combined with the Commission's busbar mapping process to mask necessary upgrades in transmission constrained areas.[61] As stated by PG&E:

> As it stands, capturing commercial interest appears to be based on circular logic:
>
> 1. With the new CAISO interconnection study selection criteria, only generators at points of interconnection (POI) with available TPD will be eligible for study selection.
>
> 2. If a POI has zero TPD available, the only way to add TPD is from new projects triggered in the TPP.
>
> 3. TPP projects are partially triggered based on commercial interest busbar mapping.
>
> 4. Commercial interest busbar mapping is influenced by the CAISO queue, but the CAISO queue no longer reflects commercial interest due to the new interconnection study selection criteria.
>
> A potential outcome of this is that commercial interest is concentrated where there was previously TPD available versus where upgrades would enable the most cost-effective development. This process, if accurate, does not give either CAISO or the Commission an accurate picture of resources that could be built.[62]

To address this circular issue, the Commission should coordinate with the CAISO on its Interconnection Process Enhancements (IPE) 5.0 proposal[63] by enhancing its busbar mapping projects to map EO resources seeking full capacity deliverability status (FCDS) when upgrades

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[61] *See* ACP-CA Opening Comments, at 4; Gridliance West, LLC, Opening Comments, at 2-3; Nextera Energy Resources, LLC, Opening Comments, at 22-23; and PG&E Opening Comments, at 8-10.

[62] PG&E Opening Comments, at 9.

[63] CAISO IPE 5.0 Draft Final Proposal (Oct. 13, 2025): https://stakeholdercenter.caiso.com/InitiativeDocuments/Draft-Final-Proposal-Interconnection-Process-Enhancements-5-0-Oct-13-2025.pdf.

are needed to address constraints preventing these resources from obtaining FCDS. The Commission should also adopt PG&E's recommendation to conduct an annual survey for entities with commercial interest to "present their new capacity projects for consideration in the busbar mapping."[64] These recommendations will help ensure transmission constrained areas without existing or planned TPD are not ignored when there is commercial interest in developing in those areas.

B. The Commission Should Consider Allowing EO Resources to Meet Any Interim Procurement Order Resulting from the Ruling, as Recommended by CalWEA, and Consider How to Avoid Conflict with other Compliance Obligations

CalWEA states that although "EO resources can charge FCDS battery resources cost-effectively during all hours, except for limited periods of very high load when batteries would be discharging," there is currently "little or no market" for EO resources.[65] CalCCA agrees that EO resources could provide reliability value through their ability to charge storage, especially given the projected decline in storage ELCCs.

CalCCA also agrees that there is little market for EO resources at this time. This is likely because EO resources are limited in their ability to contribute to existing compliance obligations.[66] Since there are other compliance requirements (*i.e.,* RA) that require deliverability, the value of EO even if allowed to meet requirements within this procurement obligation draw into question whether and how much EO would be built. The Commission should therefore

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[64] *Id.* at 9-10.

[65] CalWEA Opening Comments, at 15.

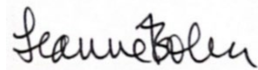
[66] The RA program only allows EO resources to count towards the charging sufficiency requirements of on-site storage resources and requires standalone storage to be fully deliverable to count towards generic RA requires and charging sufficiency requirements. In addition, the value of EO resources may be limited for RPS if transmission constraints result in curtailments.

consider allowing EO resources to count for this procurement order but also consider how the reliability of those resources is recognized and avoid conflict with other compliance obligations.

X. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments herein.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

October 31, 2025