The Commission agrees that the current non-compensated self-showing construct has been ineffective, as there is no binding commitment on LSEs to self-show and LSEs have clearly elected not to self-show despite numerous attempts to incentivize participation. Further, the self-showing attestation only requires that LSEs state their intention at the time of the self-showing. Because non-performance of self-shown local resources does not result in the allocation of a larger share of backstop costs, LSEs have little incentive to perform according to their attestation.

The Commission is persuaded that PG&E's proposal may provide a much more reliable, efficient way for the CPEs to obtain information about what local resources are under contract by LSEs, along with their expiration date. The information would be provided to the CPEs to better assess the state of the overall local portfolio before initiating the CPEs' annual solicitations and would include information on existing and new build resources under contract with LSEs. The CPEs would use this information to better assess the actual needs for short-term and long-term procurement for the three-year forward requirements and beyond. We find that PG&E's proposal will allow CPEs to better fulfill the role designated to them in D.20-06-002: to secure a portfolio of the most effective local resources, use purchasing power in constrained local areas, mitigate the need for backstop procurement, and ensure a least cost solution for customers and equitable cost allocation.[88] For these reasons, we adopt PG&E's proposal.

The Commission acknowledges CalCCA's concerns about retaining the option to sell or self-show a local resource for compensation if the CPEs obtain information about what local resources are under contract. We note, however,

88 *See* D.20-06-002 at 24.

because CPE procurements are monitored and overseen by the IE and CAM PRG, bid review and selection processes are already required to follow fair and equal consideration.

Accordingly, the non-compensated self-showing option of the CPE framework is eliminated, effective 30 days from the issuance date of this decision. For self-shown capacity that has been committed to the CPEs, the CPEs shall send a letter to LSEs with an existing and/or active attestation within 30 days of the issuance of this decision, nullifying any remaining commitments and stating that the commitments shall no longer be relied on for purposes of satisfying the CPE's compliance obligations. A template for the CPEs' letter is attached to this decision as Appendix A.

Energy Division is instead authorized to collect additional information from LSEs regarding local RA capacity that is under contract in an LSE's portfolio. Energy Division is authorized to collect the following information from each LSE about its local RA capacity under contract:

(1) Resource ID

(2) Local Area

(3) Contract Start/End Date

(4) Resource Technology Type

(5) Contracted Monthly MW Capacity for the 3-Year Forward Period

For the 2026 RA compliance year, Energy Division is authorized to send data requests in January 2025, with responses to be submitted by the LSE by February 1, 2025. Energy Division will aggregate and anonymize the information and provide the data to the CPEs for use in the CPEs' annual solicitation and procurement process. The Commission notes that the IRP Resource Data Template is already used to collect information on what resources are under contract with LSEs. The Commission requests that parties submit proposals in Track 3 on how to synchronize the existing IRP data collection process with the data requirements adopted here for the CPE framework, in order to minimize duplication and administrative burden on Commission Staff.

4.5.4. Proposal to Adjust CPE Timeline

CalCCA proposes to modify the CPE procurement timeline to move the CPE's final showing requirements up by one year.[89] CalCCA states that under the current rules about when LSEs are notified of CPE credits, the CPEs are permitted to procure up to two months prior to LSEs submitting year-ahead RA showings, which leaves LSEs with uncertainty about their system and flexible RA requirements. Further, CalCCA states that LSEs cannot assume the amount of CPE allocations and once allocations are issued, LSEs have little time to adjust procurement. CalCCA argues that because the local RA program has three-year forward requirements, the requirements generally do not change drastically from Year 2 (Y-2) to Year One (Y-1).

CalCCA recommends that the CPEs make their final showing one year in advance of LSEs' year-ahead showings, consistent with the 100 percent local RA requirement for Y-2. The deadline would apply regardless of whether the CPEs met their RA obligations so that even if a CPE did not meet its Y-2 obligation by October 31, the CPE's procurement efforts would conclude at that time. CalCCA states that if a CPE does not meet its RA obligation, CAISO would make any CPM designations (as it currently does) following LSE showings in October for Y-1. CalCCA adds that if the local RA need increases after Y-2, the CPE could procure only for the incremental need.

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89 CalCCA Track 2 Proposal at 8.

4.5.4.1. Comments on Proposal

AReM, Calpine, Microsoft, and New Leaf support CalCCA's proposal.[90] AReM agrees that uncertainty regarding CPE CAM credits, especially in the PG&E CPE's service territory, gives LSEs little time to procure. Calpine states that local capacity that the CPE is unable to secure in Y-2 is unlikely to be available in the Y-1 timeframe and so there is no need for an additional round of procurement. Microsoft states that the proposal allows LSEs to manage portfolios more effectively and avoid over-procurement from uncertainty about CPE procurement.

Cal Advocates, MRP, PG&E, and SCE oppose the proposal. Cal Advocates argues that under the proposal, CPEs would procure to meet targets two years before the compliance year, creating risks that CPE procurement may not account for variables affecting year-over-year targets, such as changes to the local requirements, LSE load migration, and other RA credits.[91] Cal Advocates states that allowing incremental procurement to address changes in the local requirements could cause significant changes to CPE credits and fail to mitigate credit uncertainty. Cal Advocates states that the CPEs use CAISO's LCR technical studies to procure for the upcoming compliance year and non-technical estimates to procure two years forward. Based on its own analysis, Cal Advocates finds that needs in the year-ahead timeframe were higher than non-technical needs in the two-year-ahead timeframe and would require the CPEs to undertake incremental procurement.

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90 AReM Comments on Track 2 Proposals at 3, Calpine Comments on Track 2 Proposals at 7, Microsoft Comments on Track 2 Proposals at 13, New Leap Comments on Track 2 Proposals at 4.

91 Cal Advocates Comments on Track 2 Proposals at 15.

MRP points out that some LSEs do not wait on CPE procurement before making system procurement decisions, as some LSEs procure via long-term contracts.[92] Even if some LSEs wait for CPE allocations, MRP states that this does not warrant the CPEs having to stop procurement two years before the compliance year, increasing the potential for the CPEs to fail to meet their local capacity requirements.

SCE argues that the proposal will not accomplish the intended objective because it discourages LSEs from timely self-showing resources.[93] SCE states that without an incentive to show resources two years out, LSEs will self-show even fewer resources to the CPE. CalCCA responds that in moving the timing up, there is no reason an LSE that has a local resource multiple years forward would not be willing to self-show.[94] PG&E states that the proposal should be considered in a later phase, as it does not address visibility challenges experienced by the CPE.[95] CalCCA responds that concerns about over-procurement risk are due to allocations not being made sufficiently in advance and if LSEs receive allocations in advance, LSEs will have time to adjust procurement plans, including selling off excess RA if needed.[96]

4.5.4.2. Discussion

Under CalCCA's proposal, the CPEs would cease local procurement in October of each year and submit their RA showings two years prior to the RA compliance year (Y-2). For example, for the 2027 RA compliance year, the CPEs

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92 MRP Comments on Track 2 Proposals at 14.

93 SCE Comments on Track 2 Proposals at 10.

94 CalCCA Reply Comments on Track 2 Proposals at 14.

95 PG&E Comments on Track 2 Proposals at 2.

96 CalCCA Reply Comments on Track 2 Proposals at 14.

would submit local RA showings in October 2025. We agree that the timeframe for LSEs to receive CPM credits, if provided, is often even tighter than the local CPE timeframe. The Commission also agrees with CalCCA that locking in CPE allocations more than one year in advance – as compared to two months - would be beneficial in that it would give LSEs more time for procurement and to negotiate favorable RA contracts on behalf of customers. We also agree that locking in CPE allocations earlier will increase certainty for LSEs to understand how much system and flexible RA they may need to procure.

Cal Advocates expresses concern that ceasing procurement two years prior to the compliance year may not mitigate credit uncertainty if the CPEs are required to conduct incremental procurement that results in further changes to CPE credit allocations. In the current RA market, the Commission is persuaded by CalCCA that the three-year forward local requirements do not change drastically from Year 2 (with a 100 percent obligation) to Year 1. Under these circumstances, we would not expect that the CPEs would have to conduct a substantial amount of incremental procurement. However, as the current RA market evolves and more system resources come online, it is possible that the CPEs would need to procure local resources that would otherwise be procured for the backstop mechanism by August.

For these reasons, the Commission adopts CalCCA's proposal to lock in CPE allocations to LSEs one year earlier, on an interim basis to be reevaluated by the end of 2027. This will be effective beginning in 2025 for the 2027 RA compliance year. The Commission authorizes Energy Division to monitor the amount of CPEs' incremental procurement, the rate of local RA deficiencies that are deferred to backstop procurement, and whether market power may be exercised by generators.

Accordingly, the following CPE procurement process is adopted (using Y to indicate the compliance year). Local CPE procurement conducted by October 31 of Y-2 for compliance year Y will be considered "locked:" that is, in Y-1, the CPEs will no longer procure for local requirements allocated in Y-2. In Y-1, the CPEs will only conduct procurement for the incremental changes between what was provided in Y-2 and CAISO's updated Local Capacity Technical study for compliance year Y. Any incremental procurement the CPE conducts for compliance year Y will be allocated to LSEs in accordance with the annual CPE and LSE allocation timelines in August and mid-September. Because these incremental needs are expected to be relatively small, LSEs should plan to receive few, if any, procurement allocations in Y-1.

For the 2026 RA compliance year and beyond, we provide the following illustration:

- In 2025, for the 2027 RA compliance year, the CPEs submit their final RA showings to Energy Division in August. Following this showing, Energy Division will allocate CPE credits for the 2026-2028 RA compliance years. The 2027 CPE allocations are "locked" and CPEs will no longer procure local resources to meet the 2027 compliance year local needs allocated to them in 2025.

- In 2026, the CPEs will only be responsible for incremental local requirements for the 2027 RA compliance year based on CAISO's annual Local Capacity Technical study, filed in the RA proceeding. In 2026, procurement conducted for the 2028 compliance year will be "locked" in the same manner as procurements in 2025 for the 2027 compliance year.

4.5.5. Proposals to Repurpose the CPE To Reduce Gas Generation

CEJA/Sierra Club state that based on Energy Division's CPE Report, it is unclear that the CPE has provided any benefit over LSEs conducting their own procurement and the CPE has not generated the competitive conditions needed to reduce prices and meet local RA requirements. CEJA/Sierra Club recommend refocusing the CPE to only procure new clean resources in local areas to plan for the retirement of gas plants. The CPE process would focus on local procurement with key elements, including: (1) need determination (based on need for local procurement using CAISO's most recent LCR study), (2) self-procurement (to allow LSEs to elect to self-procure), (3) types of resources (to only allow procurement of resources consistent with the IRP Preferred System Plan with a focus on local Distributed Energy Resources (DER)), (4) incentives (combination of IRP contractual offerings and local adders based on past local procurement), and (5) reliability metric based on loss of load hours.

PG&E recommends further exploration of a centralized planning and procurement process to reduce the state's reliance on gas generation and to determine if it is more appropriate for planning to be done on a broader basis by a state entity or a modified CPE framework.[97]

Leap, Microsoft, and PCF support CEJA/Sierra Club's proposal.[98] Leap states that it is a reasonable way to incentivize greater deployment of clean resources, including virtual power plants. Microsoft states that the principles of the proposal to create an IRP process for local RA are worth considering and that as long as IRP is not facilitating the development of new renewables and local resources, local reliability will rely on existing generation.

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97 PG&E Track 2 Proposal at 10.

98 Leap Comments on Track 2 Proposals at 3, Microsoft Comments on Track 2 Proposals at 14, PCF Comments on Track 2 Proposals at 8.

Multiple parties oppose CEJA/Sierra Club's proposal, including Calpine, CalCCA, CESA, MRP, New Leaf, SDG&E, and WPTF.[99] Several parties, such as CalCCA, New Leaf, MRP, and WPTF, oppose refocusing the CPE's role to procure new clean resources as the process of retiring gas generation should be considered within or at least aligned with the IRP proceeding.[100] CalCCA states that repurposing the CPE to procure for gas retirement would require an assessment to determine the best path to reduce gas reliance through development of new clean resources or transmission to reduce local area constraints. CESA contends that refocusing the CPE would change the purpose of the local RA program to a long-term planning and procurement process (rather than for ensuring sufficient local RA is available to CAISO). Calpine disagrees that the goal of CPE procurement should be to displace gas plants in local areas and that consideration of the gas fleet's role should account for the impact on cost and reliability at the system level.

MRP states that the CPEs have failed to promote the development of new clean resources in local areas and there is no reason to rely on them to develop meaningful clean resources. MRP disagrees with CEJA/Sierra Club's comments that state law prohibits new, long-term contracts with gas generation from CPE procurements. Calpine argues that CEJA/Sierra Club misrepresent the impact of gas generation on local air quality and counters that gas plants' impact on air quality has been shown to be generally insignificant. Calpine opposes

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[99] Calpine Comments on Track 2 Proposals at 8, CalCCA Comments on Track 2 Proposals at 8, CESA Comments on Track 2 Proposals at 8, MRP Comments on Track 2 Proposals at 11, New Leap Comments on Track 2 Proposals at 2, SDG&E Comments on Track 2 Proposals at 8, WPTF Comments on Track 2 Proposals at 8.

[100] MRP Comments on Track 2 Proposals at 11, CalCCA Comments on Track 2 Proposals at 8, New Leap Comments on Track 2 Proposals at 2, WPTF Comments on Track 2 Proposals at 8.

administratively determined incentives to procure clean resources, as it is unclear who would pay for the incentive and how the incentive cost would be recovered. SDG&E opposes CEJA/Sierra Club's proposal for DER procurement as outside the scope of the proceeding, lacking necessary details, and potentially double-counting resources.[101] SDG&E states that allowing IOUs to procure DERs where the underlying resource is included in the Preferred System Plan lacks sufficient clarity and cannot be implemented.

The Commission finds that the issues raised by CEJA/Sierra Club's proposal – aligning procurement targets, incentive design, and locational targets – warrant further exploration in a coordinated effort between the IRP and RA proceedings. As the Commission creates a pathway for a programmatic approach for long-term procurement, it is essential that procurement ensures reliability and achieves greenhouse gas reduction goals at least cost. We encourage CEJA/Sierra Club to provide input and recommendations in those efforts, including in response to the upcoming Commission staff proposal on the RCPPP, which is expected to be released in the IRP proceeding in Q4 of 2024.

4.5.6. Expansion of CPE Reporting Proposal

PG&E proposes expanding the publication of certain CPE procurement information that would otherwise qualify as confidential market-sensitive information.[102] PG&E recommends modifying the confidentiality matrix such that the CPEs would publicly provide: (1) the CPEs' local RA capacity procured on a CAISO-defined local capacity area level; (2) the CPEs' net open positions on a CAISO-defined local capacity area level; and (3) capacity purchased by the

[101] SDG&E Comments on Track 2 Proposals at 8.

[102] PG&E Track 2 Proposal at 7.

CPEs on a resource-specific level, which aligns with reporting processes of other CAM-eligible resource procurement. PG&E states that based on the past few years' experience as the CPE, PG&E does not believe that releasing this information will materially affect the competitiveness of the CPE's solicitations and could benefit the overall CPE framework by providing more granular level information to drive regulatory improvements. AReM, WPTF, and CEJA/Sierra Club support this proposal.[103]

The Commission finds PG&E's proposed expansion of the publication of CPE procurement information to be reasonable and agrees that providing additional granular information on the CPEs' procurement process could benefit the CPE framework by giving stakeholders more insight into the procurement process. As such, the Commission directs the CPEs to provide the following additional information in their Annual Compliance Reports: (1) the CPEs' local RA capacity procured on a CAISO-defined local capacity area level; (2) the CPEs' net open positions on a CAISO-defined local capacity area level; and (3) capacity purchased by the CPEs on a resource-specific level, which aligns with reporting processes of other CAM-eligible resource procurement. The Confidentiality Matrix adopted in D.22-03-034 is modified to reflect these changes, and attached to this decision as Appendix B.

4.6. Load Impact Protocols Simplification

Pursuant to the Commission's direction in D.23-06-029, on January 19, 2024, PG&E submitted the Load Impact Protocols (LIP) Simplification Working Group Report (LIP WG Report) on behalf of the LIP Simplification Working Group. In D.24-06-004, the Commission noted that no party comments on the

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103 AReM Reply Comments on Track 2 Proposals at 6, WPTF Comments on Track 2 Proposals at 13, CEJA/Sierra Club Comments on Track 2 Proposals at 18.

LIP Working Group Report in Track 1 of this proceeding and that the Commission would need additional time to consider the recommendations of the LIP Working Group Report.[104] The Commission stated that the LIP Working Group Report recommendations would be addressed in Track 2 of this proceeding. We summarize the LIP WG Report recommendations below.

4.6.1. Proposed Modifications to D.08-04-050

The LIP WG Report makes the following recommendations for the LIP process as adopted in D.08-04-050 (additions are provided in underline and deletions are struck through):[105]

(1) "Third party demand response providers" should be added to Conclusion of Law 6 to read: "6. The DR Load Impact Estimation Protocols in Attachment A should be adopted for use by <u>third party demand response providers</u>, SCE, SDG&E, and PG&E."

(2) "Third party demand response providers" should be added to Ordering Paragraph 1 to read: "1. The Demand Response (DR) Load Impact Estimation Protocols in Attachment A (Adopted Protocols) are adopted for use by <u>Third Party Demand Response Providers</u>, Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and Pacific Gas and Electric Company (PG&E)."

(3) For Protocols 1 and 3, the LIP WG Report states that a template has been started by the LIP WG Report to replace the evaluation, but the template is incomplete and needs further refinement. The Report recommends starting another Working Group and directing Energy Division or hiring a third-party to complete the template.

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104 D.24-06-004 at 64.

105 LIP WG Report at 16.

(4) Protocol 5 should be modified to replace "shall" with "may optionally" as the Report states that the mean change in energy use per year is an efficiency value that shows the total change in energy use per year and per participant, which is not useful for RA qualifying capacity (QC) values. Protocol 5 should be modified to read: "*The mean change in energy use per year <u>may optionally</u> ~~shall~~ be reported for the average across all participants and for the sum of all participants on a DR resource option for each year over which the evaluation is conducted.*"

(5) Protocol 6 should be modified to replace "10th, 30th, 50th, 70th, and 90th" percentiles with "5th, 50th, and 95th" percentiles because the Report states that a 90th percentile uncertainty window (i.e., 5th and 95th) is the standard convention in statistical regression analysis. Protocol 6 should read: "*Estimates shall be provided for the ~~10th, 30th, 50th, 70th, and 90th~~<u>5th, 50th, and 95th</u> percentiles of the change in energy use in each hour, day and year, as described in Protocols 4 and 5, for each day-type and level of aggregation described in Protocol 8*."

(6) Protocol 7 should be modified to add Table 4-1-1, which would include back-end data informing the table generator in Table 4-1 and be structured in the format defined in Tables 4-1-1 and 4-1-2. The Report states that standardizing the back-end data structure of the table generators will allow Joint Staff to stack data for ease of analysis and verification, greatly lowering review time. The Report includes a sample back-end data table for Table 4-1-1 and Table 4-1-2 but recommends another Working Group be directed to finalize the table.

(7) Protocol 8 should be modified such that the information in Table 4-1 is deemed either required or optional. The Report recommends modifying the "average across participants on average event day" as optional, as this information may be useful for IOU reporting, but modern DR programs are not consistently called with the same number of sensitive customers within the dispatch window. Protocol 8 should be modified to read:

"The information shown in Table 4-1 shall be provided for each of the following day types and levels of aggregation:

- *<u>Required</u>: Each day on which an event was called;*
- *<u>Optional</u>: The average event day over the evaluation period;*
- *<u>Required</u>: For the average across all participants notified on each day on which an event was called;*
- *<u>Required</u>: For the total of all participants notified on each day on which an event was called; and*
- *<u>Optional</u>: For the average across all participants notified on the average event day over the evaluation period."*
- *<u>Optional</u>: An average event day is calculated as a day-weighted average of all event days.*

(8) Protocol 10 should be modified to remove the last bullet that is duplicative of the requirements in Protocol 26, and to modify the "variance-covariance matrix" as optional. The Report recommends Protocol 10 statistics should not be reported, as modern regression modeling often creates individual regressions (rather than portfolio-level regressions) which means a large data set would not be useful to the Commission. Rather, the data is recommended to be calculated and stored for a one-year period after the April 1 filing. Protocol 10 should be modified to read:

"For regression based methods, the following statistics and information shall be calculated and stored by the evaluator for a period of one year after filing date of April 1 ~~reported~~:

- *Adjusted R-squared or, if R-squared is not provided for the estimation procedure, the log-likelihood of the model;*
- *Total observations, number of cross-sectional units and number of time periods;*
- *Coefficients for each of the parameters of the model;*
- *Standard errors for each of the parameter estimates;*
- *<u>Optional:</u> The variance-covariance matrix for the parameters;*

- *The tests conducted and the specific corrections conducted, if any, to ensure robust standard errors.~~; and~~*
- *~~How the evaluation assessed the accuracy and stability of the coefficient(s) that represent the load impact.~~"*

(9) In Attachment A at 78, under "5. Ex Post Evaluation for Non-Event Based Resources," the Report recommends modifying to add: "All protocols within this section (protocols 11-16) are only applicable to filers that have non-event based resources. Filers without those resources are exempt."

(10) Protocol 12 should be modified to replace "shall" with "may optionally" to read: "*The mean change in energy use per month and per year <u>may optionally</u> ~~shall~~ be reported for the average across all participants and for the sum of all participants in a DR resource option in each year over which the evaluation is conducted*."

(11) Protocol 13 should be modified to replace "10th, 30th, 50th, 70th, and 90th" percentiles with "5th, 50th, and 95th" percentiles to read: "*Estimates of the ~~10th, 30th, 50th, 70th, and 90th~~<u>5th, 50th, and 95th</u> percentiles of the change in energy use in each hour, day and year, as described in Protocols 11 and 12, for each day-type and level of aggregation described in Protocol 15, shall ~~to~~ be provided.*"

(12) Protocol 14 should be modified so that uncertainty estimates of 5th and 95th percentiles are presented since these values are required to be calculated in Protocol 13. Protocol 14 should read: "*Impact estimates shall be reported in the format depicted in Table 4-1 for all required day types, as delineated in Protocol 15. <u>In lieu of an average event hour, provide an average hour as applicable to resource. For example, provide the average on-peak window for a non-event based pricing resource like a Time-of-Use (TOU) rate</u>.*"

(13) Protocol 15 should be modified to replace "peak day" to "worst day" to read: "*The information shown in Table 4-1 shall be provided for each of the following day types for the average across all participants sum of all participants:*

- *For the average weekday for each month in which the DR resource is in effect*
- *For the monthly system worst ~~peak~~ day for each month in which the DR resource is in effect*."

"*Monthly System Worst ~~Peak~~ Day for Each Month: The day with the highest system load in each month.*"

(14) Protocol 16 should be modified to remove the last bullet, which is duplicative of Protocol 26 requirements, to read:

"*For regression based methods, the following statistics and information shall be calculated and stored by the evaluator for a period of one year after filing date of April 1 ~~reported~~:*

- *Adjusted R-squared or, if R-squared is not provided for the estimation procedure, the log-likelihood of the model*
- *Total observations, number of cross-sectional units and number of time periods*
- *Coefficients for each of the parameters of the model*
- *Standard errors for each of the parameter estimates*
- *Optional: The variance-covariance matrix for the parameters. Must be stored* only if *used to calculate the uncertainty adjusted impact percentiles, and*
- *The tests conducted and the specific corrections conducted, if any, to ensure robust standard errors.~~; and~~*
- *~~How the evaluation assessed the accuracy and stability of the coefficient(s) that represent the load impact~~*."

(15) Protocol 19 should be modified to replace "shall" with "may optionally" to read: "*The mean change in energy use per month may optionally ~~shall~~ be estimated for non-event based resources and the mean change in energy use per year shall be estimated for both event and non-event based resources for the average across all participants and for the sum of all participants on a DR resource option for each year over the forecast horizon*."

(16) Protocol 20 should be modified to replace "10th, 30th, 50th, 70th, and 90th" percentiles with "5th, 50th, and 95th" percentiles to read: "*Estimates of the ~~10th, 30th, 50th, 70th,~~*

~~and 90th~~5th, 50th, and 95th percentiles of the change in energy use in each hour, day and year, as described in Protocols 17 and 18, for each day-type and level of aggregation described in Protocol 22, shall be provided."

(17) Protocol 21 should be modified to add Table 6-1-1, which would include back-end data informing the table generator in Table 6-1 and be structured in the format defined in Table 6-1-1 and 6-1-2. This recommendation is to standardize the back-end data structure of the table generators to stack data for ease of analysis and verification. The Report includes a sample back-end data table for Tables 6-1-1 and Table 6-1-2 but recommends another Working Group finalize the table.

(18) Protocol 22 should be modified to include as optional reporting the 1 in 10 weather year, typical event day, and average weekday for each month, as these are not needed for the QC calculation. Protocol 22 should read:

"The information shown in Table 6-1 shall be provided for each of the following day types using 1-in-2 ~~and 1 in 10~~ weather conditions for the average across participants and for the sum of all participants for each forecast year:

- *Optional: For a typical event day for a 1-in-2 ~~and for a 1 in 10~~ weather year for event-based resource options.*
- *Optional: For the average weekday for each month in which the resource option is in effect for a 1-in-2 ~~and for a 1 in 10~~ weather year for non-event based resource options.*
- *For the monthly system worst ~~peak~~ day for each month in which the resource option is in effect, for a 1-in-2 ~~and for a 1 in 10~~ weather year for event-based and non-event based resources.*

Typical Event Day for a 1-in-2 ~~and 1 in 10~~ Weather Year may optionally be reported: This day type requirement applies primarily to event-based resources.

Average Week Day for Each Month In A 1-in-2 ~~and for a 1 in 10~~ Weather Year may optionally be reported: This day type requirement applies primarily to non-event based resources.

Monthly System <u>Worst</u> ~~Peak~~ Day for Each Month In a 1-in-2 ~~and for a 1 in 10~~ Weather Year: This day type applies to event-based and non-event based resources. It is meant to capture impacts for the day with the highest system load in each month. In addition to reporting all of the information shown in Table 6-1, the following information may be provided:

- *An explanation of how the weather and any other relevant day-type characteristics were chosen for the typical monthly system <u>worst</u> ~~peak~~ day.*

(19) Protocol 23 should be modified to read: *"All ex ante estimates based on regression methodologies shall <u>calculate and store</u> ~~report~~ the same statistical measures as delineated in Protocols 10 and 16 <u>for a period of one year from filing date of April 1</u>."*

(20) Protocol 26 should be modified to update Tables 9-1 and 9-3 to indicate which reporting is optional versus required.

(21) Protocol 27 should be modified to read: *"A review and comment process will be used at three stages in the implementation of the Load Impact estimation effort. These stages are:*

1. *The evaluation plan used to develop the research questions to be answered and the corresponding methods to be used to answer them;*
2. *The interim and draft final reports for all load impact studies conducted for demand response resources; and*
3. *<u>Public</u> Review of Final Reports to determine how comments were addressed.*

This process protocol is meant to ensure that the products of each of the two stages in the estimation effort benefits from a ~~public~~ review by ~~stakeholders~~, Joint Staff, <u>and the DRMEC</u> ~~and the CAISO (California Independent System Operating)~~. The Demand Response Measurement Evaluation Committee (DRMEC) would be used to initiate evaluation planning, review the final evaluation plan, and review draft load impact reports.

10.1. Evaluation Planning – Review and Comment Process

~~The DRMEC~~ Commission staff will be responsible for working with the utilities (or another identified lead entity) in developing evaluation plans for all statewide or local DR programs that are to have load impacts estimated. ~~The DRMEC will develop a process to determine which demand response programs/activities or tariffs should be evaluated and how frequently meetings should be held. The DRMC is responsible for finalizing the process of deciding which DR programs or tariffs should have impact evaluations within 90 days of this order.~~ The DRMEC will also be responsible for ensuring the issues identified in the evaluation planning sections of the load impact protocols are covered during this planning process. The following actions will be undertaken:

1. DRMEC members will identify utility or state staff leads that will be responsible for developing draft evaluation plans for selected projects. The DRMEC will also review draft and final research plans for local utility programs.

2. The DRMEC is to oversee the drafting of the IOU evaluation plans. These drafts should be sent to CPUC staff and DRMEC for comment. ~~interested utility program managers and/or evaluators and to the service list (preferably the list established for the review and authorization of DR programs in the last round) or for those who want to participate on the DRMEC for comment.~~

3. The ~~Utility or DRMEC~~ member responsible for drafting the evaluation plan is responsible for ensuring that comments are solicited from DRMEC and Joint Staff ~~key stakeholders~~ and publishing a small summary of comments received and how or if they were incorporated into the final evaluation plan for each load impact study. The comment period, including responses to them, will be set by ~~the DRMEC~~ Commission staff, taking into account the complexity and length of the documents. Absent good reason, the

period for comments on evaluation plans will be 15 business days.

4. The final evaluation plan will be made available to Joint Staff and DRMEC members ~~and parties to previous DR proceedings~~ upon request.

5. Responses to the evaluation plan comments are required by filing parties that have received comments from DRMEC, Energy Division, Public Advocates Office, California Energy Commission, or other reviewing party. Updated methods sections specifically addressing the comments made by reviewers are due by the second week of March or as determined by Energy Division.

~~**10.2. Review of Interim and Draft Load Impact Reports**~~

~~The utility or contract manager is responsible for facilitating the production of a readable first draft of the load impact report. There may also be interim reports specified in the evaluation plan that will also be subject to a review and comment process. Interim reports may be useful to the impact estimation effort by ensuring interim work products are to be consistent with the protocols. The review and comment process will consist of:~~

~~1. The interim or draft load impact report will be sent to both the members of the DRMEC and the service list and Joint Staff with a request for comments in at least 5 business days or more, within the time limit determined by Commission staff the DRMEC. The DRMEC can, at its discretion, choose to meet to discuss any the study or conduct the study review by e-mail.~~

4.6.2. Proposed Modifications to D.10-04-006, Appendix 1

The LIP WG Report next recommends modifications to Appendix 1 of D.10-04-006 because some IOUs' executive summaries are duplicative of information in their LIP reports, while other executive summaries are supplemental to the LIP reports' contents. Appendix 1 is recommended to read:[106]

> "Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company (collectively, the Utilities) may optionally ~~shall~~ prepare the following executive summary and are required to prepare the summary tables described below as a part of their annual load impact reports, and shall file this summary information in R.07-01-041 or its successor proceeding, as long as such a proceeding is open. While the executive summary is not required to be in its own, separate filing, the information required herein is still required in either the individual DR program filings or the executive summary.
>
> The executive summary (if filed separately from individual DR program filings) and the summary table are due three weeks after the individual DR program filings are due. If individual filings are due April 1, the executive summary and summary tables are due April 22.
>
> ***Optional Executive Summary ~~Requirement~~***
>
> Consistent with D.08-04-050, Attachment A, Protocol 26 under item 4, the utilities shall prepare Executive Summaries of their load impact reports. These executive summaries shall include an overview of the evaluation findings and the study's recommendation for changes to the demand response resource. In addition, it should also describe briefly the methodology, the enrollment forecast and the inputs and assumptions used for calculating the ex post and the ex ante load impact estimates. The utilities should also report the regression model specification for each demand response program.
>
> The Executive Summary shall also contain an explanation of how the Monthly System Worst ~~Peak Load~~ Day under the "1-in-2 Weather Conditions" ~~and the "1-in-10 Weather Conditions"~~ were derived and disclose the temperature or

[106] LIP WG Report at 31.

> Weather Year used for those conditions. It shall also disclose the assumption used for ex ante "portfolio basis" load impacts.
>
> ***Summary Table Requirement***
>
> The Summary Tables to be filed along with the Executive Summary of each utility's load impact reports shall include the aggregate average ex ante load impacts for each Monthly System Worst ~~Peak Load~~ Day under a 1-in-2 Weather Condition ~~and a 1-in-10 Weather Condition~~ for the next 10 years. The average impact shall be based on the hours ~~from 2 p.m.-6 p.m. or other peak hours~~ consistent with the average hours used in calculations in the current Resource Adequacy proceeding, R.23-10-011~~09-10-032~~, or a successor Resource Adequacy proceeding."

4.6.3. Proposed Modifications to D.10-06-036, Appendix B

The LIP WG Report recommends a modification to Appendix B of D.10-06-036 at 21, stating that if a filer is requesting local RA under the Slice of Day methodology, the breakdown at the sub-LAP level for every hour of the RA window is required for all months of the year. Appendix B should read:[107]

> "In order for DR programs to receive local capacity credit for RA, the load impact must be broken down by local areas. ~~However, this breakdown is not required for all months – it is only required for August.~~ If a filer is not requesting any local RA, breakdown at the Sub-LAP level in ex ante are not required."

4.6.4. Proposal on Confidentiality

Lastly, the LIP WG Report states that third-party DR providers have been interpreting confidentiality rules differently when filing LIPs, such that information in enrollment projections may be publicly available in some filings

[107] LIP WG Report at 31.

and not others.[108] The Report states that this creates an unfair advantage between third parties. The Report notes that D.20-06-031 only provides that: "The Load Impact Protocol (LIP) reports and qualifying capacity values from a demand response provider's LIP results shall be posted publicly to the maximum extent allowable, while protecting customer privacy and market sensitive information of demand response providers by adhering to the Commission's existing confidentiality practices."[109] The Report contends that Energy Division Staff has authority to determine what the "maximum extent possible" should be and that Energy Division should clarify in the LIP Filing Guide as to expectations.

The Report recommends that the following be kept confidential: (1) customer forecast scenarios, (2) customer forecast rationale, and (3) anything that violates existing Commission confidentiality policies (*e.g.*, 15/15 rule).

4.6.5. Comments on LIP WG Report

Several parties recommend full adoption of the LIP WG Report, including Council/OhmConnect, Leap, PG&E, SCE, and SDG&E.[110] These parties point out that a broad range of stakeholders participated in the WG process and developed consensus recommendations following robust discussion. Council/OhmConnect state that the recommendations will reduce the number of analyses needed and volume of the LIPs reports, but also ensure that Energy Division has sufficient data to make a well-informed determination of DR NQC

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108 LIP WG Report at 33.

109 *Id.* (citing D.20-06-031 at OP 17).

110 Council/OhmConnect Comments on Track 2 Proposals at 2, PG&E Comments on Track 2 Proposals at 11, SCE Comments on Track 2 Proposals at 12, SDG&E Comments on Track 2 Proposals at 9, Leap Comments on Track 2 Proposals at 2.

values. SDG&E urges adoption before December 2024 and states that adopting it after makes incorporations into the 2024 LIP Reports challenging.

CEJA/Sierra Club oppose the proposal to eliminate a public process as some stakeholders may not have the resources to participate in a working group but have an interest in the LIPs determination.[111]

4.6.6. Discussion

The Commission appreciates the thorough discussion and efforts of the LIP Simplification Working Group, as well as stakeholders' submission of additional comments on the LIP WG Report in Track 2. We recognize that the LIP WG Report recommends directing a further Working Group process to address certain issues, particularly for modifications to Protocols 1, 3, 7, and 21. However, due to the staffing and resource constraints, an additional Working Group process is not feasible at this time. Regarding the modifications to Protocols 1 and 3, we encourage any party, the Demand Response Measurement and Evaluation Committee, or Energy Division to submit proposals for consideration in a future phase.

For the proposed modifications to Protocol 7 and 21, as adopted in D.08-04-060, the Report describes Tables 4-1-1, 4-1-2, 6-1-1, and 6-1-2 as a first attempt to create a standardized back-end data structure that requires further development in a Working Group. As there is insufficient record to adopt the modifications to Protocols 7 and 21, we decline to adopt Tables 4-1-1, 4-1-2, 6-1-1, and 6-1-2 as modifications to Protocols 7 and 21. Table 4-1 and Table 6-1, however, are complete and accordingly, we adopt these modifications.

[111] CEJA/Sierra Club Comments on Track 2 Proposals at 19.

With respect to other proposed modifications to D.08-04-050, as discussed above, we recognize that these are consensus recommendations that represent the positions of a broad range of parties and find the recommendations to be reasonable. As such, the other modifications to D.08-04-050 are adopted. The adopted changes are outlined in Appendix C, attached to this decision.

With respect to the proposed modifications to D.10-04-006, Appendix 1, the Commission recognizes that these are consensus recommendations that represent the positions of a broad range of parties and finds the recommendations to be reasonable. As such, the modifications to D.10-04-006, Appendix 1, are adopted. The adopted changes are outlined in Appendix C, attached to this decision.

With respect to the proposed modifications to D.10-06-036, Appendix B, the Commission recognizes that these are consensus recommendations that represent the positions of a broad range of parties and finds the recommendations to be reasonable. As such, the modifications to D.10-06-036, Appendix B, are adopted. The adopted changes are outlined in Appendix C, attached to this decision.

With respect to the confidentiality proposals, the Commission finds that the WG has not put forth a developed proposal for consideration. The WG Report requests that Energy Division clarify which information should be deemed market-sensitive, confidential information and the recommendation lacks sufficient record development. As such, we decline to adopt this recommendation. We note that there is an ongoing Data Working Group in Phase One, Track Two of R.22-11-013, and parties are encouraged to participate in that process.

5. Summary of Public Comments

Rule 1.18 allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding. No public comments were submitted.

6. Comments on Proposed Decision

The proposed decision of ALJ Debbie Chiv in this matter was mailed to the parties in accordance with Pub. Util. Code Section 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on __________, and reply comments were filed on _____________ by ________________.

7. Assignment of Proceeding

Alice Reynolds is the assigned Commissioner and Debbie Chiv is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. Additional vetting and further analysis of Energy Division's revised PRM analysis is needed. The data gathering and reconciliation for the inputs and assumptions that underlie the LOLE study are time-consuming and resource intensive.

2. Due to a lack of participation by LSEs in the non-compensated self-showing option, CPEs do not have access to critical information before initiating the CPE solicitation as to what local resources are under contract by LSEs, what the most effective local resources are to secure, and what the true needs are in designated local areas.

3. The current non-compensated self-showing construct has been ineffective, as there is no binding commitment on LSEs to self-show and LSEs have elected not to self-show despite numerous attempts to incentivize participation.

4. PG&E's proposal to eliminate and replace the non-compensated self-showing option will allow CPEs to better fulfill the role designated to them in D.20-06-002: to secure a portfolio of the most effective local resources, use purchasing power in constrained local areas, mitigate the need for backstop procurement, and ensure a least cost solution for customers and equitable cost allocation.

5. Locking in CPE allocations more than one year in advance, as compared to two months, would be beneficial in that it would give LSEs more time for procurement and more time to negotiate favorable RA contracts on behalf of customers.

6. Locking in CPE allocations earlier will increase certainty for LSEs to understand how much system and flexible RA they may need to procure.

7. PG&E's proposed expansion of the publication of CPE procurement information would provide additional granular information on the CPEs' procurement process that could benefit the CPE framework by giving stakeholders more insight into the procurement process.

8. The recommendations from the LIP Working Group Report, with some exceptions, represent consensus positions from a broad range of parties.

Conclusions of Law

1. Energy Division should be authorized to undertake a further revision of the 2026 PRM analysis to correct identified errors and distribute it to the service list in December 2024.

2. Consideration of the revised PRM analysis and the 2026 PRM should be deferred to Track 3 of this proceeding.

3. It is more realistic and reasonable for Energy Division Staff to update the RA LOLE study every two years for consideration in the RA proceeding.

4. PG&E's proposal to eliminate the non-compensated self-showing option may provide a more reliable, efficient way for the CPEs to obtain information about what local resources are under contract by LSEs. PG&E's proposal to eliminate the non-compensated self-showing option should be adopted, with modifications.

5. CalCCA's proposal to lock CPE allocations to LSEs one year in advance is reasonable and should be adopted, with modifications, on an interim basis to be reevaluated at the end of 2027.

6. PG&E's proposal to expand the publication of CPE procurement information is reasonable and should be adopted.

7. The recommendations from the LIP Working Group Report, with some exceptions, are reasonable and should be adopted.

8. All assigned Commissioner and assigned Administrative Law Judge rulings should be affirmed.

9. All pending motions should be denied.

O R D E R

IT IS ORDERED that:

1. Energy Division is authorized to undertake a further revision of the planning reserve margin (PRM) analysis to correct errors identified in comments and to distribute it to the service list in this proceeding in early December 2024. The revised PRM analysis will be considered by the Commission in Track 3 of this proceeding.

2. Energy Division is authorized to update the Resource Adequacy (RA) Loss of Load Expectation study every two years for consideration in the RA proceeding.

3. The non-compensated self-showing option of the central procurement entity (CPE) framework is eliminated, effective 30 days from the issuance date of this decision. For self-shown capacity that has been committed to the CPEs, the CPEs shall send a letter to load-serving entities with an existing and/or active attestation within 30 days of the issuance of this decision, nullifying any remaining commitments and stating that the commitments shall no longer be relied on for purposes of satisfying the CPE's compliance obligations. A template for the CPEs' letter is attached to this decision as Appendix A.

4. Energy Division is authorized to collect additional information from load-serving entities (LSEs) regarding local Resource Adequacy (RA) capacity that is under contract in an LSE's portfolio. Energy Division is authorized to collect the following information from each LSE about its local RA capacity under contract:

(1) Resource ID

(2) Local Area

(3) Contract Start/End Date

(4) Resource Technology Type

(5) Contracted Monthly Megawatt (MW) Capacity for the 3-Year Forward Period

For the 2026 RA compliance year, Energy Division is authorized to send data requests in January 2025, with responses to be submitted by the LSE by February 1, 2025. Energy Division will aggregate and anonymize the information and provide the data to the CPEs for use in the CPEs' annual solicitation and procurement process.

5. California Community Choice Association's proposal to lock central procurement entity (CPE) allocations to load-serving entities (LSE) one year earlier is adopted, on an interim basis. This will be effective in 2025 for the 2027 Resource Adequacy (RA) compliance year and will be reevaluated by the end of 2027. The following CPE procurement process is adopted (using Y to indicate the compliance year).

(a) Local CPE procurement conducted by October 31 in Y-2 for compliance year Y will be considered "locked:" in Y-1, the CPEs will no longer procure for local requirements allocated in Y-2.

(b) In Y-1, the CPEs will only conduct procurement for the incremental changes between what was provided in Y-2 and the California Independent System Operator's updated Local Capacity Technical study for compliance year Y. Any incremental procurement the CPE conducts for compliance year Y will be allocated to LSEs in accordance with the annual CPE and LSE allocation timelines in August and mid-September.

6. Energy Division is authorized to monitor the amount of CPEs' incremental procurement, the rate of local RA deficiencies that are deferred to backstop procurement, and whether market power may be exercised by generators.

7. The central procurement entities (CPE) shall provide the following additional information in their Annual Compliance Reports: (1) the CPEs' local Resource Adequacy (RA) capacity procured on a California Independent System Operator (CAISO)-defined local capacity area level; (2) the CPEs' net open positions on a CAISO-defined local capacity area level; and (3) capacity purchased by the CPEs on a resource-specific level, which aligns with reporting processes of other Cost Allocation Mechanism (CAM)-eligible resource procurement. The Confidentiality Matrix adopted in Decision (D.) 22-03-034 is modified to reflect these changes, and is attached to this decision as Appendix B.

8. Modifications to the Load Impact Protocols requirements, as outlined in Appendix C attached to this decision, are adopted.

9. All assigned Commissioner and assigned Administrative Law Judge rulings are affirmed.

10. All pending motions are denied.

11. Rulemaking 23-10-011 remains open.

This order is effective today.

Dated _____________, at Sacramento, California.

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 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)	Application 24-05-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND DIRECT ACCESS CUSTOMER COALITION'S JOINT MOTION TO STRIKE PORTIONS OF PACIFIC GAS AND ELECTRIC COMPANY'S FALL UPDATE TESTIMONY

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October 31, 2024

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SUMMARY OF RECOMMENDATIONS

PG&E's[1] Fall Update directly contradicts the Scoping Ruling and Judge Fox's October 8, 2024 Ruling expressly deeming PG&E's "mitigation" proposals out of scope. The proposals should be stricken from PG&E's Fall Update.

1 Acronyms and defined terms used in the Summary of Recommendations are defined in the body of this brief.

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

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Pursuant to Rule 11.1 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the California Community Choice Association[2] (CalCCA) and the Direct Access Customer Coalition[3] submit this *Joint Motion to Strike Portions of Pacific Gas and Electric Company's Fall Update Testimony* (Motion) in the above-captioned *Application of Pacific Gas and Electric (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)* (Application).

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 DACC is a regulatory advocacy group comprised of educational, governmental, commercial and industrial customers that utilize direct access for all or a portion of their electrical energy requirements. Pursuant to Rule 1.8, DACC has authorized CalCCA to make this filing on its behalf.

This Motion is required because PG&E insists on continuing to advance a policy proposal the Commission has expressly excluded from the scope of this proceeding. Specifically, PG&E's Fall Update Testimony asks the Commission to "mitigate" the impact of the Commission's recently released market price benchmarks (MPB) by placing a cap on one or more of those MPBs.[4] PG&E made a nearly identical Resource Adequacy (RA) MPB mitigation proposal in its Application and prepared testimony[5] and the Commission concluded that proposal was beyond the scope of this proceeding.[6]

An October 8 email ruling requested comments on procedural matters related to the updated RA MPB (October 8 Ruling). The October 8 Ruling reinforced the limited scope of this proceeding: it expressly affirmed the question of "whether the MPB methodology should be changed" remains firmly "outside of the scope" of this proceeding.[7] PG&E still put forward its MPB proposal in the Fall Update.

In response to the October 8 ruling, PG&E requested a Commission order directing parties "to brief the issue of whether the Commission should mitigate the impact of the escalated MPBs pending an evaluation of the calculation methodology in a future rulemaking[.]"[8] The Commission declined to issue the Order PG&E requested. PG&E decided to make the MPB proposal in its Fall Update anyway.

Despite these unequivocal Commission pronouncements, PG&E not only audaciously revives its MPB mitigation proposal in its Fall Update but expands its proposal to both the RA and RPS MPBs. PG&E's proposal threatens to undermine the integrity of this ERRA Forecast

4 PG&E Fall Update Testimony, Attachment C.
5 *See* PG&E-02C, Chapter 2.
6 Assigned Commissioner's Scoping Memo and Ruling at 3 (Aug. 1, 2024).
7 October 8 Ruling at 3.
8 Pacific Gas and Electric Company's (U 39 E) Response to Administrative Law Judge's Email Ruling Regarding Procedural Mechanisms at 6 (Oct. 14, 2024).

proceeding and standard Commission practice in at least three ways. First, per Commission Rule 7.3,[9] the scoping memo establishes the issues to be addressed in any proceeding. By extension, any issues the scoping memo expressly excludes from—or does not include in—the issues to be addressed in a proceeding should not be introduced by any party and are subject to being stricken. Second, as CalCCA explained in its Protest responding to PG&E's Application, policy proposals are beyond the scope of ERRA Forecast proceedings; these proceedings are aimed narrowly at implementing prior Commission decisions. Third, PG&E's proposal is severely prejudicial to intervening parties. The expedited timeline characteristic of ERRA Forecast proceedings challenges parties' ability to analyze the investor-owned utilities' Fall Update testimony, issue discovery, and prepare comments on issues *within scope* in a matter of weeks. There is simply not enough time for parties to also analyze and address *out-of-scope* proposals within that timeline.

The Commission should therefore strike any discussion related to PG&E's MPB mitigation proposal from its Fall Update testimony. Appendix A to this Motion lists the specific portions of PG&E's Fall Update testimony that should be stricken.

I. PG&E'S PROPOSAL TO MITIGATE THE RA AND RPS MPBS IS OUTSIDE THE SCOPE OF THIS PROCEEDING

In its May 15, 2024, Application, PG&E proposed a conditional cap on the RA MPB (MPB mitigation proposal). Under that proposal, in the event the 2024 Final and 2025 Forecast RA MPBs exceeded the 2024 Forecast System RA MPB, PG&E proposed to continue to apply the lower 2024 Forecast System RA MPB for PCIA ratemaking purposes.[10] This proposal would have applied indefinitely, *i.e.*, until some unknown point in the future when the Commission completed

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9 Commission Rules of Practice and Procedure Rule 7.3 (Scoping Memos).

10 A.24-05-009, *Application of Pacific Gas and Electric Company (U 39 E) for 2025 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation*, pp. 32-33 (May 15, 2024); A.24-05-009, Pacific Gas and Electric Company Prepared Testimony, p. 2-18 (May 15, 2024).

an examination of the RA MPB and RA market in a yet-to-be-determined docket.[11] PG&E also sought Commission approval to implement a tracker during that period to record the difference in the value of the RA attributes transferred between the Portfolio Allocation Balancing Account (PABA) and ERRA using the artificially capped RA MPB and the actual RA MPBs (and, at some point in the future, to impose the accumulated balance on its customers).[12]

Ultimately, the Commission ruled PG&E's proposal beyond the scope of this proceeding, finding "this proceeding is the incorrect venue to address these issues, given the clear direction in prior decisions regarding the ratemaking calculation methodologies that shall be applied in ERRA Forecast applications, and given the expedited schedule and record development needed to reach resolutions for these matters."[13] The Commission encouraged PG&E to submit a Petition for Rulemaking to address its larger concerns surrounding the RA MPBs and to raise potential solutions.[14]

On October 4, 2024, the Commission's Energy Division released the 2024 Final RA MPBs and 2025 Forecast RA MPBs used to calculate the PCIA.[15] Subsequently, the ALJs in each ERRA Forecast proceeding issued the October 8 Ruling requesting party comments on the impact of the RA MPBs on the *scoping issues*, and whether the Commission should consider procedural mechanisms to address any such impacts.[16] Importantly, the October 8 Ruling did not change the

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11 PG&E-02C at 2-19.

12 PG&E Prepared Testimony at 2-18.

13 Scoping Memo and Ruling at 3.

14 *Id.*

15 *See* Market Price Benchmark Calculations 2024 (Oct. 4, 2024). Accessible at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/2024-market-price-benchmarks.pdf. Note that Energy Division initially released the updated Energy Index and RPS MPBs on October 2, 2024, but there was a delay in issuing the RA MPBs. Energy Division subsequently revised the RPS MPBs via errata on October 11, 2024.

16 A.24-05-009, *Email Ruling Requesting Party Comments on Procedural Mechanisms* (Oct. 8, 2024) (Ruling Requesting Comments).

scope of this proceeding, and in fact specified that "[c]omments should be limited to the scope of this proceeding, and not address issues outside of the scope, such as whether the MPB methodology should be changed."[17] Accordingly, the scope of this proceeding continues to expressly exclude PG&E's original MPB mitigation proposal.

Nonetheless, PG&E again attempted to try to address issues beyond the scope of this proceeding. In response to the October 8 ruling, PG&E requested a Commission order directing parties "to brief the issue of whether the Commission should mitigate the impact of the escalated MPBs pending an evaluation of the calculation methodology in a future rulemaking[.]"[18] The Commission declined to issue the Order PG&E requested. *It could not be clearer* at this point in this proceeding that PG&E's MPB mitigation proposals are out of scope.

II. PG&E'S PROPOSAL TO MITIGATE THE RA AND RPS MPBS SHOULD BE STRICKEN

A. PG&E's MPB Mitigation Proposal Violates the Commission's Rules

The Commission's rules support a broad interpretation of relevance. Under Commission Rule 13.6(a), California's "technical rules of evidence . . . need not be applied in hearings" before the Commission, and the Commission need not exclude evidence "merely by application of rules governing admissibility, competency, weight or foundation."[19] But this Motion does not seek the exclusion of PG&E's testimony based merely on the rules governing admissibility, competency, weight or foundation (although the Joint Movants do not concede those rules permit PG&E's testimony). PG&E's testimony discussing its MPB mitigation proposal must be stricken because

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17 Ruling Requesting Comments.

18 Pacific Gas and Electric Company's (U 39 E) Response to Administrative Law Judge's Email Ruling Regarding Procedural Mechanisms at 6 (Oct. 14, 2024).

19 Rule 13.6(a).

the Commission expressly excluded that proposal from the scope of this proceeding. Therefore, by definition, PG&E's proposal is not relevant to the scoping issues.

Commission Rule 7.3 states the scoping memo for the proceeding "shall determine . . . issues to be addressed[.]" By extension, any issues the scoping memo expressly excludes—or does not include—from the issues to be addressed in a proceeding should not be introduced by any party and are subject to being stricken. Here, the Scoping Memo specifically addressed PG&E's RA MPB cap proposal and concluded this proceeding is the incorrect venue to address that proposal. The Scoping Memo therefore *expressly excluded* PG&E's RA MPB cap proposal from the issues to be addressed in the proceeding.

The MPB mitigation proposal PG&E advances in its Fall Update testimony is substantially similar to the RA MPB cap it proposed in its prepared testimony. While PG&E's original proposal was limited to a single "alternative ratesetting scenario" in which the Commission mitigated the impacts of the RA MPB on bundled generation rates by capping that MPB at its 2024 Forecast level, PG&E's Fall Update testimony offers three mitigation scenarios. Each of these mitigation scenarios involve a cap on the RA MPB, and one scenario involves a cap on the Renewable Portfolio Standard (RPS) MPB, as well.[20] In short, PG&E not only reintroduces but attempts to expand a proposal that the Scoping Memo expressly excluded from the list of issues to be addressed in this proceeding. PG&E's MPB mitigation proposal therefore violates Rule 7.3, is beyond the scope of this proceeding, and should be stricken.

PG&E will allege its mitigation proposal is relevant to Scoping Issue 1 (whether PG&E's forecasted procurement revenue requirement is reasonable) and should therefore not be stricken. While CalCCA does not concede PG&E's proposal is relevant to Scoping Issue 1, that argument

[20] PG&E Fall Update Testimony, Attachment C.

misses the point. PG&E's mitigation proposal is no more relevant to Scoping Issue 1 now than it was when the Scoping Memo was issued, and the Scoping Memo nevertheless *expressly excluded* PG&E's mitigation proposal from the scope of this proceeding.[21] The Scoping Memo's express pronouncement would carry no meaning if PG&E were permitted to introduce a near-replica of its stricken proposal at this stage of the proceeding.

B. PG&E's Out-of-Scope Proposal Severely Prejudices Intervening Parties

Testimony on issues beyond the scope of a proceeding is always properly stricken, but it is particularly important the Commission hold parties accountable in expedited proceedings like this ERRA Forecast proceeding in order to ensure all parties can meaningfully participate.[22] The Fall Update process in ERRA Forecast proceedings requires intervening parties to analyze the IOU's updated revenue requirements and rates, issue discovery, and prepare comments on the scoping issues in a matter of weeks, sometimes less. In this proceeding, parties must simultaneously prepare reply briefs while analyzing and preparing comments on the Fall Update. The compressed timeline characteristic of ERRA Forecast proceedings makes it imperative that the Commission prohibit the IOU from introducing new, out-of-scope proposals in the Fall Update.

PG&E's MPB mitigation proposal is particularly egregious because the Commission already excluded it from the scope of this proceeding. Allowing PG&E to flagrantly ignore the Commission's clear scoping memo and reintroduce a policy proposal at this late stage in the proceeding would be extremely prejudicial to the parties. Without swift Commission action striking PG&E's proposals from its Fall Update testimony, parties will be forced to divert resources to address an out-of-scope proposal on an expedited timeline—effectively hindering

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[21] Scoping Memo at 3.

[22] *See* Commission Rule 13.6(a) (the Commission need not apply the technical rules of evidence, but shall preserve the rights of parties to meaningfully participate in the proceeding and to public policy protections).

parties' ability to address issues that are in scope. Granting this Motion expediently will allow the Commission to avoid wasting time and resources on PG&E's out-of-scope proposal during the compressed window of time in which it must prepare a Proposed Decision in this case.

C. The Commission Does Not Permit Policymaking in ERRA Forecast Proceedings

Even if PG&E were advancing its MPB mitigation proposal for the first time in its Fall Update Testimony (which it is not), and the Scoping Memo had not addressed that proposal (which it did), the proposal would nevertheless be beyond the scope of this ERRA Forecast proceeding and properly stricken.

As PG&E and the other utilities have reminded stakeholders time and again, the purpose of ERRA Forecast dockets is to assure timely recovery of the utilities' actual electric procurement costs, as required by Public Utilities Code Section 454.5(d)(3), among other Commission decision-mandated tasks. The approval of program costs, the appropriate rate mechanisms to recover those costs, and the allocation of those costs among different customer groups is pre-determined via authorizing Commission decisions in other proceedings including the utility's general rate case. The scope of ERRA Forecast proceedings is limited to evaluating the IOUs' compliance with prior Commission orders, rules, or policies.[23]

The Commission has forbidden policymaking in ERRA Forecast cases unless a prior Commission decision has ordered such policymaking.[24] For example, the Scoping Memo in A.17-06-005 (PG&E's 2018 ERRA Forecast application) rejected the inclusion of certain CCA-proposed changes to the PCIA ratemaking methodology, stating:

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23 *See, e.g.*, A.13-05-015, *Scoping Memo and Ruling of Assigned Commissioner* at 4 (Sept. 12, 2013).
24 *See, e.g.,* D.18-01-009 at 10 (finding that policy issues are properly addressed in other dockets); *see also id.* at 14, Conclusion of Law (COL) 2 and Ordering Paragraph (OP) 2 (denying PG&E's request to modify its line loss calculation).

> The CCA parties are proposing changes to existing methods of calculation, and do not allege non-compliance with Commission rules, decisions, and resolutions on the part of PG&E. Such proposals should be addressed in proceedings with input from other investor-owned utilities and interested parties.[25]

Fairness requires the Commission similarly prohibit consideration of PG&E's MPB mitigation proposal in this proceeding. As the IOUs have argued previously, dockets like rulemakings and consolidated applications apply to all California utilities and are noticed to, and generally include as parties, a broader set of stakeholders.[26] Proposals to change the PCIA ratemaking framework, therefore, can and should be raised in those types of dockets, such that all interested parties have an opportunity to evaluate and respond to those proposals. It is unlikely all parties with an interest in PG&E's MPB mitigation proposal have notice of it being raised here.

PG&E itself has represented to the Commission the narrow and ministerial scope of ERRA Forecast applications—and how narrow it should be going forward. In Rulemaking (R.) 17-06-026, the Commission sought input into a change in the schedule for the ERRA Forecast proceedings that would replace the November Update with an October Update.[27] CalCCA argued this change should be accompanied by a corresponding change to the filing date of the IOUs' ERRA Forecast applications in order to largely maintain the same pre-Update timeline for parties to understand and develop a robust record.[28] PG&E disagreed, arguing ERRA Forecast proceedings do not include the type of policymaking that require substantial record development: "The existing schedule (*i.e.*, from June 1st to early November) is more than sufficient to litigate

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25 A.17-06-005, *Scoping Memo and Ruling of Assigned Commissioner* at 3-4 (Aug. 24, 2017).

26 *See* A.18-06-001, *PG&E Reply to Protests and Responses* at 2-3 (Jul. 16, 2018) (addressing rulemakings).

27 Rulemaking (R.) 17-06-026, *E-Mail Ruling Requesting Comments on ERRA Timing Proposal* at 5 (May 20, 2021).

28 R.17-06-026, *California Community Choice Association's Comments in Response To Staff's ERRA Timing Proposal* at 4-12 (June 15, 2021).

what are mostly routine and non-controversial non-Update-related aspects of the Joint Utilities' ERRA Forecast proceedings."[29] PG&E also stated it agreed with comments from another party that the ERRA Forecast proceedings "by design" should consist of "perfunctory updates."[30] It also observed that complications surrounding the Fall (at the time, November) Update were likely indicative of "growing pains" associated with the new PCIA methodology and not indicative of what it called "*routine review* of the ERRA Forecast applications."[31] PG&E also agreed that future ERRAs, including this 2025 ERRA Forecast, should "be *more routine* than have been experienced in the past two or three years."[32] PG&E should not be allowed to now distance itself from its own prior statements to push through approval of a massive change to the PCIA ratemaking framework through what PG&E itself describes as a "routine" and expedited proceeding.

PG&E's MPB mitigation proposal puts the cart before the horse by proposing a novel PCIA ratemaking component before the Commission even undertakes the process of addressing RA market scarcity or modifying the calculation of the RA MPB, let alone agreeing with PG&E's diagnosis of the problems with the RA market or the RA MPB and resolving that process. If the Commission had taken up RA market scarcity and adopted a RA (or RPS) value "mitigation measure" in a separate rulemaking or consolidated application proceeding, it may have been reasonable for PG&E to implement that Commission decision in this ERRA Forecast proceeding. But the Commission has not done so, and therefore, PG&E's proposal is premature and untethered

[29] R.17-06-026, *The Joint Utilities' Opening Comments on Proposed Decision Resolving Phase 2 Issues Related To Energy Resources Recovery Account Proceedings* at 6 (Jan. 6, 2022) (emphasis added).

[30] R.17-06-026, *Reply of Southern California Edison Company (U 338-E) To Administrative Law Judge's Ruling Requesting Comments on The Market Price Benchmark Issue Date* at 5 (Sept. 22, 2021) (emphasis added).

[31] R.17-06-026, *Reply of Southern California Edison Company (U 338-E) To Administrative Law Judge's Ruling Requesting Comments on The Market Price Benchmark Issue Date* at 5 (Sept. 22, 2021) (emphasis added).

[32] *Id*.

to any Commission direction or consideration. Until and unless the Commission undertakes the review and makes the determination PG&E appears to desire but has not yet requested, PG&E must comply with *existing* Commission decisions, including D.18-10-019 and D.19-10-001. Those decisions require PG&E to use the 2025 Forecast MPBs to determine its Indifference Amount and require PG&E to use the 2024 Final MPBs to determine its 2024 year-end balance in the PABA. PG&E's MPB mitigation proposals are therefore beyond the scope of this proceeding and properly stricken.

III. CONCLUSION

For the foregoing reasons, the Commission should strike the portions of PG&E's Fall Update testimony proposing changes to the RA and RPS MPBs as detailed in Appendix A attached to this Motion.

Respectfully submitted,

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On behalf of the California Community Choice Association and the Direct Access Customer Coalition

October 31, 2024

APPENDIX A

Page and Line Number	Basis for Motion to Strike
Table of Contents, Subheading D, Attachment C	Out of scope, irrelevant
Page 2, lines 28-30	Out of scope, irrelevant
Page 4, lines 16-21	Out of scope, irrelevant
Page 5, lines 17-32 and page 6, lines 1-9, including footnote 4.	Out of scope, irrelevant
Page 35, partial line 1 "Subject to mitigations for the unprecedented MPBs,"	Out of scope, irrelevant
Page 35, lines 25-32	Out of scope, irrelevant
Attachment C (page AtchC-1 through AtchC-16)	Out of scope, irrelevant

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 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)	Application 24-05-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY BRIEF

PUBLIC VERSION

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October 31, 2024

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SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

- PG&E[1] audaciously proposes the same, specific "mitigation measures" the Commission already deemed out of scope of this proceeding. Those measures modify the PCIA framework and transgress the limited purpose of ERRA forecast proceedings. The utility cites no precedent and no evidence of extraordinary circumstances that would justify deviating from a near-decade of precedent preventing revisions to the Commission's indifference framework in an ERRA forecast proceeding—let alone circumstances and evidence that would allow a party to directly defy a Commission Scoping Ruling.

- CalCCA's proposal for allocating ESA costs actually reflects the activities driving procurement costs, mirrors PG&E's own recommendation from last year's case and prevents cost shifting.

- The Commission should adopt the recommendations in CalCCA's opening brief.

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

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 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation (U39E)	Application 24-05-009

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY 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] the California Community Choice Association[3] (CalCCA) hereby submits this reply brief in the above-captioned *Application of Pacific Gas and Electric Company (PG&E) for Adoption of Electric Revenue Requirements and Rates Associated with its 2025 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation* (Application).

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2 Assigned Commissioner's Scoping Memo and Ruling at 5 (Aug. 1, 2024).

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.

In response to an October 8 email ruling requesting comments on procedural matters related to the updated Resource Adequacy (RA) market price benchmark (MPB) (October 8 Ruling), PG&E requested a Commission order directing parties "to brief the issue of whether the Commission should mitigate the impact of the escalated MPBs pending an evaluation of the calculation methodology in a future rulemaking[.]"[4] The Commission did not issue the Order PG&E requested. But PG&E decided to brief the issue anyway. PG&E's opening brief includes an extended discussion of the Commission's recently-updated MPBs and concludes—without a scintilla of supporting analysis—those MPBs "will result in a clearly inequitable allocation of revenue requirements between bundled service and departing load customers."[5] Based on the "cost shift" it alleges but does not prove, PG&E urges the Commission to "establish a mitigation for the purpose of 2025 ratesetting"[6] and promises to propose a specific MPB mitigation in its Fall Update testimony.[7]

PG&E's request is familiar because it is lifted directly from its Application and prepared testimony in this case. In its prepared testimony, PG&E forecasted sharp increases in the RA MPB and proposed a "mitigation measure" for 2025 ratesetting purposes.[8] CalCCA and the Direct Access Customer Coalition (DACC) protested PG&E's Application and argued MPB "mitigation measures" are beyond the scope of ERRA Forecast proceedings, because these proceedings require the utility to *implement* prior decisions and do not permit new policy proposals. The Commission agreed, stating "this proceeding is the incorrect venue to address [the RA MPB issue], given the

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4 Pacific Gas and Electric Company's (U 39 E) Response to Administrative Law Judge's Email Ruling Regarding Procedural Mechanisms at 6 (Oct. 14, 2024).

5 Opening Brief of Pacific Gas and Electric Company (U 39 E) (PG&E Opening Brief) at 2.

6 *Id*. at 4.

7 *Id*. at 7.

8 PG&E-02C, Chapter 2.

clear direction in prior decisions regarding the ratemaking calculation methodologies that shall be applied in ERRA forecast applications, and given the expedited schedule and record development needed to reach resolution for these matters."[9] The October 8 Ruling reinforces the limited scope of this proceeding by expressly affirming that the question of "whether the MPB methodology should be changed" remains firmly "outside of the scope" of this proceeding.[10]

Recognizing the scope of this proceeding expressly prevents PG&E from re-raising its MPB proposal, the utility's opening brief still suggests the Commission disregard the Scoping Ruling on account of the State's ratemaking standards. However, PG&E's argument studiously ignores the fact the Commission has affirmed repeatedly that just and reasonable ratemaking in an ERRA Forecast proceeding is limited to implementing prior Commission decisions reached under that same standard. PG&E's Opening Brief cites no precedent from prior ERRA proceedings and does not point to any evidence of extraordinary rate increases that justify deviating from that precedent.

To be clear, CalCCA is well-aware the Resource Adequacy (RA) market is changing, and market scarcity has driven prices high. Those issues have rightly caused concern regarding the valuation of the investor-owned utilities' (IOU) capacity portfolios among customers, load-serving entities (LSE) including community choice aggregators (CCA), and the Commission. The Commission has been proactive on this issue, both by encouraging PG&E to file a Petition for Rulemaking to address concerns regarding the RA MPB and raise potential solutions[11] and by

[9] Assigned Commissioner's Scoping Memo and Ruling at 3 (Aug. 1, 2024) (Scoping Memo).

[10] October 8 Ruling at 3.

[11] Scoping Memo at 3.

issuing a Ruling to solicit input regarding the impact of the RA MPB on the scoping issues in this proceeding.

While those concerns merit careful consideration in a rulemaking, no party has shown, or can show, in this expedited proceeding, that the current PCIA framework does not produce indifference in each of the three IOU service territories. Whereas PG&E simply assumes revisions to the PCIA framework are not only forthcoming but will reduce the value of its RA portfolio, revisions to the PCIA framework may cause the value of the IOUs' RA portfolios to increase, depending on the implementation of the new Slice-of-Day (SOD) framework. Southern California Edison Company (SCE), for instance, has proposed changes to the manner in which it calculates the quantity of RA capacity in its portfolio using a "SOD RA Effectiveness Factor" which, if approved, would have the impact of increasing the value of that portfolio and reducing that utility's indifference amount by approximately **$460 million**.[12] The bottom line is, changes to the PCIA framework to address changes in the RA market are far from a foregone conclusion, and there is no discussion in the record, let alone consensus, regarding how those changes will impact the value of PG&E's RA portfolio. Therefore, if the Commission were to "mitigate" the MPBs as PG&E recommends, it could conceivably *worsen* a future rate spike for bundled customers when PG&E begins to amortize its accumulated tracker balance (inclusive of interest).

The good news is the Commission has the time to consider this issue deliberately and holistically. Low brown power prices counteract the impacts of elevated RA and RPS MPBs, significantly reducing costs to bundled customers. In PG&E's service territory, lower market

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[12] *See Application of Southern California Edison Company (U 338-E) for Approval of its 2025 ERRA Forecast Proceeding Revenue Requirement*, A.24-05-007, Prepared Direct Testimony of Brian Dickman on behalf of the California Community Choice Association in Southern California Edison Company's 2025 ERRA Forecast Proceeding at 21-22 (Sept. 3, 2024).

prices for electricity reduce ERRA costs by $840 million in 2024.[13] Compared to PG&E's initial filing, declines in forecasted market prices for electricity as reflected in the Energy Index MPB reduced the cost to procure energy for bundled customers by an additional [redacted] million.[14] PG&E barely mentions these facts in an opening brief full of hyperbole on the impacts of MPB changes. As a result, rates are projected to be stable or decreasing across all three utility service territories.[15] This affords the Commission room to follow the approach *it already outlined* in its Scoping Ruling: carefully consider RA market changes in response to a petition for rulemaking, receive party input, and evaluate necessary modifications to the PCIA framework *outside of* these expedited ERRA Forecast proceedings.

Because the Commission expressly deemed PG&E's "mitigation measure" out of scope in this proceeding, and appropriately did not grant PG&E's request to propose those mitigation measures again, CalCCA, jointly with the Direct Access Customer Coalition (DACC), files contemporaneously with this Reply Brief a Motion to Strike those portions of PG&E's Fall Update. Out of an abundance of caution, CalCCA's comments on PG&E's Fall Update Testimony also will respond to the specific mitigation measures PG&E proposes in its Fall Update. The arguments in this reply brief respond to PG&E's unsupported conclusion that elevated MPBs cause a "cost shift" requiring *ad hoc* modifications to the Commission's PCIA framework in an ERRA Forecast proceeding.

This brief also responds to PG&E's discussion of its proposed modifications to its existing Electric Supply Administration (ESA) cost allocation methodology. PG&E correctly criticizes its

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13 PG&E Fall Update Testimony at 17-18.

14 Comparing Line 2 of Table 13-1 in PG&Es Prepared Testimony and Fall Update Testimony.

15 PG&E Fall Update Testimony forecasts system average bundled generation rates will decrease by approximately 0.7 cents/kWh or 2%. PG&E Fall Update Testimony at 5.

existing "net revenue requirement" allocation methodology for resulting in unintended outcomes when the value of its generation portfolio increases and PCIA rates go negative. But rather than transitioning to a "gross revenue requirement" methodology—which is not only a solution PG&E previously supported but would address the very problem causing it to abandon its current approach—PG&E proposes a contrived allocation methodology based on General Rate Case (GRC) revenue requirements in an effort to align itself with SCE. However, SCE's ESA-cost allocation methodology is not Commission-authorized. Nor can the Commission achieve alignment across the three IOUs by approving PG&E's proposal because San Diego Gas & Electric Company's (SGD&E) proposed approach to ESA cost allocation diverges from PG&E's proposal.[16] This disjointed situation—where PG&E's position is constantly shifting in a siloed proceeding that excludes the other two IOUs—underscores why ratemaking policy should not take place in an ERRA Forecast proceeding.

PG&E's proposed methodology shifts costs to departed customers by allocating the vast majority of ESA costs to the PCIA, including costs incurred exclusively on behalf of bundled customers. In contrast, the gross revenue requirement methodology CalCCA supports equitably allocates ESA costs to the Portfolio Allocation Balancing Account (PABA), Energy Resource Recovery Account (ERRA), and Cost Allocation Mechanism (CAM), recognizing that PG&E's ESA activities are driven by all three accounts.

Having originally argued that CalCCA's gross revenue requirement methodology "ensure[s] that all customers bear an equitable portion of costs to manage the shared generation

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[16] *Application of San Diego Gas and Electric Company for Approval of its 2025 Electric Procurement Revenue Requirement Forecasts, 2025 Electric Sales Forecasts, and GHG-related Forecasts*, A.24-05-010, Tr. Vol. 1 at 44:15-21.

portfolio",[17] PG&E now criticizes that methodology for producing allocations that are vulnerable to fluctuating energy prices.[18] But PG&E's criticism rings hollow because PG&E proposes to allocate non-ESA common costs (*i.e.*, the costs of collateral) using a methodology that is vulnerable to the very same market volatility. The Commission should therefore reject PG&E's proposal and adopt a methodology that allocates PG&E's Common Costs (ESA and non-ESA) to the PABA (including PCIA vintages), ERRA and CAM based on gross revenue requirements. Moreover, the Commission should apply any methodology it adopts in this proceeding <u>prospectively</u>. Applying the methodology to the 2024 true-up as PG&E proposes would require the Commission to reconfigure revenue requirements it previously found reasonable and would constitute retroactive ratemaking.

I. PG&E'S OPENING BRIEF INCORRECTLY APPLIES THE LEGAL STANDARD

PG&E points to the California Constitution, multiple sections of the Public Utilities Code, and a recent appellate decision for the proposition that the Commission not only has the authority to, but is required to, prevent cost shifting between bundled and departed load customers.[19] CalCCA could not agree more. It is that very requirement that prevents the Commission from straying from the PCIA framework it established to prevent cost-shifting and adopt an "MPB mitigation measure" in this proceeding.

The Commission's mechanism for ensuring bundled and unbundled customer indifference to load departure is the PCIA framework. As the Commission explained when it replaced the

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[17] *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2024 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation*, A.23-05-012, Pacific Gas and Electric Company's (U 39 E) Response to Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs (Aug. 16, 2023).

[18] PG&E Opening Brief at 28.

[19] *Id*. at 9-12.

original "cost responsibility surcharge" with the PCIA: "The PCIA is intended to preserve the indifference concept adopted in D.02-11-022[.]"[20] The central mechanism of the PCIA framework is a forecasted "indifference amount" that compares each utility's total power portfolio costs to market benchmarks that reflect the value of that portfolio. Faithful application of the PCIA framework—including both the costs and value sides of that coin—produces indifference, whereas failure to do so produces cost shifts in violation of California law.

Importantly, Section 366.2(g) of the Public Utilities Code—which PG&E does not mention in its opening brief—requires that "estimated net unavoidable electricity costs paid by the customers of a community choice aggregator **shall be reduced** by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits."[21] That language is mandatory, not permissive. It *requires* the Commission to convey to departed customers the value of PG&E's generation portfolio retained by bundled customers, and it does not permit the Commission to defer that value.

To the extent PG&E or any party believes the current PCIA framework does not accurately estimate any component of the costs or value of PG&E's generation portfolio (and therefore does not produce indifference), that party should follow the Scoping Ruling's advice and file a Petition for Rulemaking allowing the Commission to evaluate changes to the framework.[22] Nothing in the legal standards relevant to this proceeding require the Commission to make *ad hoc* changes to any component of the PCIA framework in ERRA Forecast proceedings. And doing so would

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20 Decision (D.) 06-07-030 at 25.

21 Cal. Pub. Util. Code § 366.2(g) (emphasis added).

22 *See* Commission Rules of Practice and Procedure, Rule 6.3.

contravene nearly a decade of Commission precedent stating such changes are inappropriate.

Indeed, while the Commission's obligation under Section 451 of the Public Utilities Code to set just and reasonable rates governs ERRA Forecast proceedings, the Commission has established a clear rule against setting ratemaking policy in ERRA Forecast applications.[23] As PG&E and the other utilities have reminded stakeholders time and again, the purpose of ERRA Forecast dockets is to assure timely recovery of the utilities' actual electric procurement costs, as required by Public Utilities Code Section 454.5(d)(3), among other Commission decision-mandated tasks. The approval of program costs, the appropriate rate mechanisms to recover those costs, and the allocation of those costs among different customer groups is pre-determined via authorizing Commission decisions in other proceedings including the utility's general rate case. The scope of ERRA Forecast proceedings is limited to evaluating the IOUs' compliance with prior Commission orders, rules, or policies.[24]

The Commission has largely forbidden policymaking in ERRA Forecast cases unless a prior Commission decision has ordered such policymaking.[25] For example, the Scoping Memo in A.17-06-005 (PG&E's 2018 ERRA Forecast application) rejected the inclusion of certain CCA-proposed changes to the PCIA ratemaking methodology, stating:

> The CCA parties are proposing changes to existing methods of calculation, and do not allege non-compliance with Commission rules, decisions, and resolutions on the part of PG&E. Such proposals should be addressed in proceedings with input from other investor-owned utilities and interested parties.[26]

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[23] 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).

[24] *See, e.g.*, A.13-05-015, *Scoping Memo and Ruling of Assigned Commissioner* at 4 (Sept. 12, 2013).

[25] *See, e.g.,* D.18-01-009 at 10 (finding that policy issues are properly addressed in other dockets); *see also id.* at 14, Conclusion of Law (COL) 2 and Ordering Paragraph (OP) 2 (denying PG&E's request to modify its line loss calculation).

[26] A.17-06-005, *Scoping Memo and Ruling of Assigned Commissioner* at 3-4 (Aug. 24, 2017).

Fairness requires the Commission similarly prohibit consideration of MPB mitigations in this proceeding. As the IOUs have argued previously, dockets like rulemakings and consolidated applications apply to all California utilities and are noticed to, and generally include as parties, a broader set of stakeholders.[27] Proposals to change the PCIA ratemaking framework, therefore, can and should be raised in those types of dockets, such that all interested parties have an opportunity to evaluate and respond to those proposals. It is unlikely all parties with an interest in PG&E's MPB mitigation have notice of it being raised here.

PG&E itself has represented to the Commission the narrow and ministerial scope of ERRA Forecast applications—and how narrow it should be going forward. In Rulemaking (R.) 17-06-026, the Commission sought input into a change in the schedule for the ERRA Forecast proceedings that would replace the November Update with an October Update.[28] CalCCA argued this change should be accompanied by a corresponding change to the filing date of the IOUs' ERRA Forecast applications in order to largely maintain the same pre-Update timeline for parties to understand and develop a robust record.[29] PG&E disagreed, arguing ERRA Forecast proceedings do not include the type of policymaking that require substantial record development: "The existing schedule (*i.e.*, from June 1st to early November) is more than sufficient to litigate *what are mostly routine and non-controversial* non-Update-related aspects of the Joint Utilities'

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27 *See* A.18-06-001, *PG&E Reply to Protests and Responses* at 2-3 (Jul. 16, 2018) (addressing rulemakings).

28 Rulemaking (R.) 17-06-026, *E-Mail Ruling Requesting Comments on ERRA Timing Proposal* at 5 (May 20, 2021).

29 R.17-06-026, *California Community Choice Association's Comments in Response To Staff's ERRA Timing Proposal* at 4-12 (June 15, 2021).

ERRA Forecast proceedings."[30] PG&E also stated it agreed with comments from another party that the ERRA Forecast proceedings "by design" should consist of "perfunctory updates."[31] It also observed that complications surrounding the Fall (at the time, November) Update were likely indicative of "growing pains" associated with the new PCIA methodology and not indicative of what it called "*routine review* of the ERRA Forecast applications."[32] PG&E also agreed that future ERRAs, including this 2025 ERRA Forecast, should "be *more routine* than have been experienced in the past two or three years."[33] PG&E should not be allowed to now distance itself from its own prior statements to push through approval of a massive change to the PCIA ratemaking framework through its Update testimony in what PG&E itself describes as a "routine" and expedited proceeding.

II. THE COMMISSION SHOULD NOT CONSIDER "MITIGATION MEASURES" THAT MODIFY THE PCIA FRAMEWORK IN THIS PROCEEDING

PG&E changes its tune in this proceeding from one about "rate impacts" to one about "cost shifts." It originally proposed a "mitigation" to the RA MPB in this case because it believed updated MPBs would drive a significant increase in bundled customer generation rates. In its prepared testimony, PG&E alleged that if its forecast of RA forward prices materialized, and if the RA MPB reflecting those prices were not mitigated, it would "result in high bundled service customer generation-related rates and bills[.]"[34] PG&E estimated updated RA MPBs would cause

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30 R.17-06-026, *The Joint Utilities' Opening Comments on Proposed Decision Resolving Phase 2 Issues Related To Energy Resources Recovery Account Proceedings* at 6 (Jan. 6, 2022) (emphasis added).

31 R.17-06-026, *Reply of Southern California Edison Company (U 338-E) To Administrative Law Judge's Ruling Requesting Comments on The Market Price Benchmark Issue Date* at 5 (Sept. 22, 2021) (emphasis added).

32 *Id*. (emphasis added).

33 *Id*.

34 PG&E-02C at 2-2.

bundled generation rates to increase by 27% or 4.2 cents per kWh compared to rates in effect on July 1, 2024, translating into an approximately $23.00 monthly bill impact for a PG&E residential bundled service customer.[35]

CalCCA cautioned against jumping to PG&E's conclusions. In its protest to the Application, CalCCA noted that RA is only one component of the value of PG&E's overall PCIA-eligible portfolio, and that low brown power prices could have an offsetting impact on high RA prices.[36] As a result of that dynamic, elevated RA MPBs do not necessarily translate to bundled customer generation rate increases.

CalCCA's prediction turned out to be correct. Although updated RA MPBs are significantly higher than the 2024 Forecast MPB, low brown power prices reduce the cost to procure energy to serve PG&E's bundled customers. PG&E notes that lower market prices for electricity reduced ERRA costs $840 million in 2024.[37] Compared to PG&E's initial filing, declines in forecasted market prices for electricity as reflected in the Energy Index MPB reduced the cost to procure energy for bundled customers by an additional [redacted] million.[38] As a result, PG&E's system average bundled customer generation rates are forecast to *decrease* by 0.7 cents per kWh or by 2%, despite incorporating the updated 2024 Actual and 2025 Forecast MPBs.[39]

Those updated rate forecasts required PG&E to change the focus of its story in order to justify the same remedy it originally sought. PG&E now claims "mitigation" is necessary principally to protect against the "inequitable allocation of revenue requirements between bundled

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35 *Id*. at 2-1.

36 CalCCA Protest at 20.

37 PG&E Fall Update Testimony at 17-18.

38 Comparing Line 2 of Table 13-1 in PG&Es Prepared Testimony and Fall Update Testimony.

39 PG&E Fall Update Testimony at 5.

service and departing load customers."[40] While PG&E appears to recognize bundled customer generation rates will not increase in 2025, it nevertheless invites the Commission to adopt rates fully reflecting low brown power prices but only partially reflecting the other components valuing PG&E's generation portfolio (*all* to the benefit of bundled customers and to the detriment of departed customers).[41] According to PG&E, absent a mitigation, the MPBs "will result in massive and unlawful cost shifts to remaining bundled service customers[.]"[42]

PG&E has not, however, supplied any evidence that demonstrates a cost shift, let alone a "massive" one. Its cost-shift discussion begins and ends with the fact that RA MPBs are "elevated." But elevated MPBs are not, on their own, evidence of a cost-shift; rather, they are evidence that the value of PG&E's RA portfolio has increased relative to last year's forecast. In order for a party to prove a cost shift, it would have to at least quantify that cost shift. It would have to demonstrate the RA MPB does not accurately represent the capacity value of PG&E's PCIA-eligible generation portfolio, demonstrate an alternative to the current MPB that accurately represents that value, and demonstrate the impacts of that alternative on revenue requirements. PG&E has demonstrated none of those facts; it has not even taken the first step the Commission laid out for it to demonstrate those facts: filing a petition for rulemaking. Yet it jumps to the conclusion that the RA MPB must be mitigated to avoid a cost shift. In short, PG&E has chosen a solution benefiting bundled customers, but it still has not defined the problem.

PG&E's opportunism stands out—neither of the other IOUs have taken PG&E's audaciously one-sided approach in their respective ERRA Forecast cases. In sharp contrast with

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40 PG&E Opening Brief at 2.

41 *Id*. at 3-4.

42 *Id*. at 14.

PG&E, SDG&E acknowledges "[t]he Scoping Memo to [its ERRA Forecast proceeding] indicates that the ERRA Forecast is not the appropriate proceeding to address changes to any previously approved rate or benchmark calculations" and therefore proposes "no such changes to the PCIA methodology for RA or the Indifference Amount" in its October Update filing.[43] SCE similarly proposes no "mitigation" to the RA MPB itself, but in response to the updated MPBs, proposes to change the way it applies System, Flexible, and Local RA MPBs to its PCIA portfolio in a way that allegedly matches PG&E's existing approach.[44] No IOU or party to this proceeding therefore shares PG&E's "sky-is-falling" narrative, even though several parties (including CalCCA) have acknowledged that changes to the RA market merit the Commission's attention in a rulemaking following this year's ERRA Forecast proceedings. The Commission should not, therefore, assign weight to PG&E's complaints, should not assume those complaints will lead to a decrease in the value of the IOUs' capacity portfolios, and should not adopt any MPB "mitigation measures" in this proceeding—especially one so clearly designed to be one-sided. Instead, it should continue to encourage PG&E to file a Petition for Rulemaking and allow parties to develop a record on RA market issues in that proceeding.

III. THE "GROSS REVENUE REQUIREMENT" METHODOLOGY EQUITABLY ALLOCATES COMMON COSTS TO CUSTOMERS

A. The Commission Should Allocate PG&E's Common Costs Based on the Gross Revenue Requirement Methodology

PG&E allocates its Common Costs—consisting chiefly of ESA costs and the costs of

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43 A.24-05-010, SDG&E October Update Testimony at SM-6. The scope of SDG&E's ERRA Forecast proceeding is substantially similar to the scope of the instant proceeding, and both scoping memos include language expressly excluding changes to the RA MPB calculation from the scope of the proceeding. *See* A.24-05-010, Scoping Memo at 5.

44 A.24-05-007, SCE Alternative October Update, SCE-09 at 136 (stating SCE's approach "also aligns with how PG&E and SDG&E apply the RA MPBs for purposes of PCIA ratemaking" and citing in turn to A.24-05-009, PG&E-02C at Chapter 10, p. 17-18)

posting collateral—to ERRA, CAM and PABA based on the net revenue requirements associated with each account.[45] That methodology, however, is flawed. As PG&E explains in its opening brief, when the value of its portfolio increases and PCIA rates go negative (as several vintages have recently experienced), the net revenue requirement methodology produces absurd results (*i.e.* negative allocations to PABA).[46] The most straightforward way to correct that flaw is to allocate Common Costs to ERRA, CAM and PABA based on the *gross* revenue requirements associated with each account. That methodology eliminates the impacts of volatility in the value of PG&E's generation portfolio because allocations would be based only on the <u>costs</u> of that portfolio. The gross revenue requirement methodology therefore resolves the very issue driving PG&E's desire to modify its existing approach.

PG&E criticizes the gross revenue requirement methodology in its opening brief, stating that methodology "can have distortionary impacts to bundled customers due to fluctuating bundled load costs influenced by energy market prices."[47] In other words, high market prices drive higher ERRA allocations, all else equal.[48]

But PG&E's criticism of the gross revenue requirement methodology rings hollow, for three reasons. <u>First</u>, PG&E supported the gross revenue requirement methodology just a year ago. In response to a ruling seeking comments on "Fixed Generation Cost" issues in PG&E's 2024 ERRA Forecast proceeding, PG&E stated that methodology "will ensure that all customers bear an equitable portion of costs to manage the shared generation portfolio" and "eliminate[s] the risk

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45 PG&E Opening Brief at 27.

46 *Id*. at 28.

47 *Id*.

48 *Id*.

that bundled customers bear a disproportionate share of [ESA] costs."[49] Second, whereas PG&E proposes to allocate nearly all ESA costs to the PCIA, PG&E proposes to allocate non-ESA common costs, such as the costs of posting collateral, to ERRA, CAM and PABA based on the net revenue requirement methodology.[50] Under that methodology, allocations to ERRA would vary with energy market volatility just as they would under CalCCA's proposed gross revenue requirement methodology. Third, the impact of fluctuations in energy market prices cuts in both directions. High energy prices would lead to higher allocations to ERRA, but lower energy prices would lead to lower ERRA allocations. In other words, the gross revenue requirement methodology can frequently lead to lower allocations to bundled customers.

In contrast with the straightforward gross revenue requirement methodology, PG&E proposes to allocate ESA costs largely to the Legacy UOG and 2009 PCIA vintages based on the General Rate Case (GRC) revenue requirement associated with utility-owned generation (UOG) resources recorded to those PABA subaccounts.[51] But that contrived proposal creates more problems than it solves. First, PG&E's proposal would allocate the vast majority of ESA costs (over 87 percent) to the PABA, virtually no ESA costs to ERRA, and only a small fraction of ESA costs to the CAM.[52] But, as CalCCA explained in its opening brief, a portion of PG&E's ESA costs have nothing to do with the management of PCIA-portfolio resources, and are incurred exclusively on bundled customers' behalf.[53] Under PG&E's proposal, departed customers would pay 60 percent of the costs that were not incurred on their behalf – resulting in an impermissible

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49 A.23-05-012, Pacific Gas and Electric Company's (U 39 E) Response to Administrative Law Judge's Ruling Directing Parties to Comment Regarding Fixed Generation Costs (Aug. 16, 2023).

50 PG&E Opening Brief at 27.

51 *Id*.

52 PG&E-03 at 23.

53 CalCCA Opening Brief at 27-29.

cost-shift.[54] Second, PG&E's proposal would significantly reduce the allocation of costs to CAM, because that proposal arbitrarily limits CAM allocations based on the GRC revenue requirements of a single UOG CAM facility.[55] In effect, this shifts ESA costs away from PCIA-exempt customers, another failing of PG&E's proposed cost allocation methodology.[56]

The primary reason PG&E advances this contrived solution is to align with what it believes to be SCE's Commission-authorized ESA cost allocation methodology.[57] But that objective is misguided because SCE's ESA cost allocation approach has not been authorized by the Commission, contrary to PG&E's opening brief.[58] The Commission should also consider that whereas SDG&E initially sought to match PG&E's ESA cost allocation methodology in its pending ERRA Forecast proceeding, its proposed approach no longer aligns with PG&E (or with SCE, for that matter). In its Fall Update testimony, SDG&E changed its ESA cost allocation proposal, noting: "SDG&E is aware that PG&E is also considering changes to its O&M allocation methodology but SDG&E believes that its proposal stands on its own as the most equitable method, and considers it to be the least affected by potential fluctuations in the energy market."[59] That means the Commission cannot achieve alignment between the IOUs by approving PG&E's proposal.

Ultimately, if the Commission desires the worthwhile objective of alignment across all three IOUs with respect to common cost allocation methodologies, the Commission should

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54 *Id*. at 27-28.

55 *Id*. at 30.

56 *Id*.

57 PG&E Opening Brief at 29.

58 CalCCA Opening Brief at 26.

59 A.24-05-010, Updated Prepared Direct Testimony of Sheri Miller on behalf of San Diego Gas & Electric Company at SM-4.

consider those methodologies in a rulemaking or other consolidated proceeding with a single record that allows the Commission and parties to more effectively compare each IOU's practices. Until then, the Commission should approve the gross revenue requirement methodology, because that methodology best avoids cost shifting and comes closest to equitably allocating PG&E's Common Costs based on the activities causing those costs.

B. The Commission Should Apply Any Modification to PG&E's Common Cost Allocation Methodology Prospectively

PG&E argues it is appropriate to apply a revised methodology for 2024 true-up purposes "as this proceeding routinely considers a true-up of balancing account balances as part of the revenue requirements established for the forecasted year."[60] In effect, PG&E asks the Commission to use the true-up—a mechanism intended to reconcile actual with forecasted values—for the purpose of unsettling revenue requirements the Commission previously found reasonable and approved. The Commission should decline to do so.

The balancing accounts that form the structure for the PCIA true-up are aimed at accuracy; they allow the utility to minimize cost recovery lag by permitting ratesetting based on forecast costs and revenues, followed by a reconciliation to actual recorded values. Balancing accounts, however, do not and cannot rewrite the methodologies that led the Commission to find recorded values reasonable in the first place.

Section 728 of the California Public Utilities Code requires rates to be set prospectively.[61] California courts have held that once a rate has been formally found reasonable by the Commission and charges collected accordingly, the Commission shall not order the payment of reparations or

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[60] PG&E Opening Brief at 29.

[61] Cal. Pub. Util. Code § 728.

refunds, even on the ground of unreasonableness.[62] This is generally known as the rule against "retroactive ratemaking." The 5th District Court of Appeal's application of the rule against retroactive ratemaking is instructive here. In *The Ponderosa Telephone Co. v. Public Utilities Com.*, 197 Cal. App. 4th 48 (5th Dist. 2011), certain rural telephone companies appealed the Commission's decision to allocate the proceeds from the redemption of Rural Telephone Bank (RTB) stock to the telephone companies' ratepayers. The appellants contended that the Commission's action resulted in improper retroactive ratemaking because the allocation of RTB stock redemption proceeds to ratepayers related to a past cost that was factored into an approved rate.

The court agreed, stating:

> The Commission's allocation of the [RTB stock redemption proceeds] to the ratepayers rests on the premise that the amounts collected pursuant to the approved general rates were excessive because they overstated the cost of debt. Thus, <u>*the Decision retroactively revises costs that formed the basis for prior general rates.*</u> This is precisely the type of action prohibited by the retroactive ratemaking doctrine. Such a rollback of general rates already approved by the Commission and refund of amounts collected pursuant to such approved rates constitutes retroactive ratemaking and therefore is invalid.[63]

Stated another way, the law and Commission precedent allows the Commission to true up costs via balancing accounts to improve accuracy and accelerate cost recovery,[64] but it does not allow the Commission to revise the nature of the costs underlying approved rates.

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62 *Pacific Tel. & Tel. Co. v. Pub. Util. Comm'n*, 62 Cal.2d 634, 655 (1965); *City of Los Angeles v. Pub. Util. Com.*, 7 Cal. 3d 331, 356 (1972).

63 *The Ponderosa Telephone Co. v. Public Utilities Com.*, 197 Cal. App. 4th 48, 63-64 (5th Dist. 2011) (emphasis added).

64 *See* D.18-10-019 at 79 (stating "the Commission's ERRA ratemaking process relies on an annual forecast to set each IOU's annual revenue requirement, and then allows the IOUs to track their actual costs and actual revenues in the ERRA balancing account, so that any overcollection or undercollection is "trued up" and used to adjust a subsequent annual revenue requirement either upwards or downwards.").

Applying this law to the circumstances of an ERRA Forecast case, the Commission can true-up costs and revenues, but it cannot retroactively revise the methodologies used to calculate those costs in the first place. Here, D.23-12-022 resolving PG&E's 2024 ERRA Forecast application approved PG&E's 2024 Forecast procurement revenue requirements, including its ERRA, PABA and CAM revenue requirements, concluding it was reasonable to adopt those revenue requirements.[65] Those revenue requirements reflected the allocation of PG&E's Common Costs based on its existing allocation methodology. By asking the Commission to apply a different cost allocation methodology for the purposes of the 2024 true-up, PG&E effectively asks the Commission to undo its prior determination that PG&E's 2024 forecast procurement revenue requirements (in particular, its ERRA, PABA and CAM revenue requirements) are reasonable. Per the appellate court's analysis in *Ponderosa*, however, undoing that prior determination would constitute retroactive ratemaking, because it would revise the costs that formed the basis for prior general rates.

The fact that PG&E's generation related balancing accounts include a mechanism that allow PG&E to true-up forecast 2024 costs and revenues with actual 2024 values does not change the retroactive ratemaking analysis. Again, balancing accounts and the true-up mechanism are meant to allow PG&E to timely recover forecast costs and promptly correct for actual costs and revenues. The balancing accounts are not meant to permit *post hoc* modifications to approved revenue requirements based on new proposals made after rates went into effect—whether or not PG&E believes those approved rates are unreasonable or unfair.

To illustrate the difference between the purpose of the true-up and the way in which PG&E proposes to use it: consider a group of four friends that goes out to dinner. The friends anticipate

[65] D.23-12-022 at 11-12; COL 6, OP 1.

dinner will cost $100 and agree to split the bill evenly ($25 each). The bill ends up being $200. A true-up would adjust each attendee's contribution from $25 to $50 in order to reflect the actual bill. A true-up would not, however, change each attendee's relative contribution to that bill, effectively pulling out the rug from under the attendees. PG&E's proposal to apply a new common cost allocation methodology to the 2024 true-up would have the latter, fundamentally unfair effect. The Commission should therefore adopt any modifications to PG&E's Common Cost allocation methodology on a prospective basis only.

IV. CONCLUSION

For the foregoing reasons, CalCCA requests that the Commission decline to consider or adopt "mitigation measures" that modify the PCIA framework in this proceeding and adopt the recommendations in CalCCA's opening brief.

Dated: October 31, 2024

Respectfully submitted,

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NOVEMBER FILINGS

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Agenda ID# 23023
ENERGY DIVISION **RESOLUTION E-5327**
December 5th, 2024

R E S O L U T I O N

Resolution E-5327. Addresses proposals submitted by portfolio administrators detailing their intended multi-distributed energy resource integrated demand side management frameworks and programs pursuant to Decision (D.) 23-06-055.

PROPOSED OUTCOME:

- Approves with modifications and clarifications the proposed multi-distributed energy resource integrated demand side management (multi-DER IDSM) frameworks and programs pursuant of D.23-06-055 in Tier 3 Advice Letters.
- Requires PG&E, SCE, and SoCalGas to submit subsequent Advice Letters in accordance with applicable CPUC policies, including the program launch checklist and third-party Tier 2 Advice Letter requirement, prior to program commencement to provide further details of their plans. If the pilot program is a third-party program and falls below a $5 million budget threshold or is less than three years in duration, the IOU must file a Tier 1 AL for each third-party contract.
- Requires BayREN, I-REN, MCE, SoCalREN, and 3C-REN to submit a Tier 2 Advice Letter in accordance with the program launch checklist should they wish to expand their programs beyond the scope described in their Advice Letter for portfolio years 2024-2027.

SAFETY CONSIDERATIONS:

- There are no safety considerations associated with this resolution.

ESTIMATED COST:

- Does not increase costs beyond the energy efficiency budgets adopted in D.23-06-055.

By Advice Letters (AL):

- PG&E 4876-G/7209-E, Filed on March 15, 2024.
- SCE 5249-E, Filed on March 15, 2024.
- SoCalGas 6276-G, Filed on March 15, 2024.
- BayREN 25-E, Filed on March 15, 2024.
- I-REN 4-E/4-G, Filed on March 14, 2024.
- MCE 74-E, Filed on March 15, 2024.
- SoCalREN 18-E/18-G, Filed on March 15, 2024.
- 3C-REN 10-E/9-G, Filed on March 15, 2024.

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1. SUMMARY

This Resolution approves, with modifications and clarifications, the intended multi-distributed energy resource (multi-DER) integrated demand side management (IDSM) frameworks and programs submitted via Tier 3 Advice Letter (AL) by Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company (SoCalGas), San Francisco Bay Area Regional Energy Network (BayREN), Inland Regional Energy Network (I-REN), Marin Clean Energy (MCE), Southern California Regional Energy Network (SoCalREN), and Tri-County Regional Energy Network (3C-REN) pursuant of Decision (D.) 23-06-055.

2. BACKGROUND

Starting in 2007 with D.07-10-032, the CPUC challenged the utilities to integrate their customer demand side programs, such as energy efficiency (EE), self-generation, advanced metering, and demand response (DR).[1] This early form of IDSM persisted until 2018, when the CPUC staff proposed to repurpose existing IDSM budget to specifically target limited integration of aspects of energy efficiency and DR. The goal was to gain additional demand response value for little incremental cost, as IDSM funds are primarily used for DR when EE investments are already being made. The proposal

[1] *See* D.07-10-032 at OP 5.

was adopted in D.18-05-041 and resulted in many energy efficiency-demand response (EE-DR) IDSM programs across the portfolio administrators (PAs).[2]

The proposed multi-DER IDSM programs pursuant to D.23-06-055 represent a progression from these previous approaches to IDSM. While the approach approved in D.18-05-041 focused on the integration of DR programs with EE programs, D.23-06-055 provides a multi-DER approach focused on ongoing or permanent load shifting or load reduction, rather than event-based DR.[3] This new emphasis offers greater flexibility and opportunity to provide ratepayers with a more comprehensive range of technologies to fulfill their needs and to move toward the state's goal and statutory requirement for full decarbonization by 2045 or sooner.[4]

In D.23-06-055, the CPUC stated that portfolio administrators (PAs) may propose processes for customers to implement multi-DER projects and receive rebates or incentives for non-EE IDSM measures through their EE programs.[5] To do this, PAs were given the option to submit Tier 3 advice letters no later than March 15, 2024, for programs to be launched during the portfolio period (2024-2027). The ALs were required to include details of the use of non-EE funding sources, measurement approaches including any methods that will be used to ensure that impacts on consumption are not double-counted, and references to applicable rules and approved budgets from non-EE CPUC approved funding sources that will govern the distribution of those funds.[6]

The Decision allowed PAs to set aside 2.5 percent, or $4 million, whichever is greater, up to a maximum of $15 million, from within their total budgets during 2024-2027 approved in the Decision.[7] The Decision stated that this program funding is on a pilot basis and shall not be spent on event-based DR because such interventions do not necessarily result in ongoing or permanent load shifting or load reduction.

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[2] *See* D.18-05-041 at OP 10.
[3] *See* D.23-06-055 at OP 29.
[4] CA SB 100 (DeLeon, 2018)
[5] *See* D.23-06-055 at OP 28.
[6] *Id.*
[7] *See* D.23-06-055 at OP 29.

The goal of these IDSM programs would be to use an EE program delivery channel to integrate a comprehensive program strategy and allow a customer to install a multi-DER project using multiple funding streams from a range of IDSM sources, as long as there is an EE component. This means that the IDSM programs would be allowed to offer incentives from non-EE funding sources.

Further details on each PA's proposed multi-DER IDSM frameworks or programs can be found in the Appendix of this Resolution.

NOTICE

Notice of each PA advice letter was made by publication in the CPUC's Daily Calendar. A copy of each PA AL was served to interested parties and parties on the service list of R.13-11-005 either electronically or via the U.S. mail in accordance with Section 4 of General Order 96-B.

PROTESTS

Advice Letters PG&E 4876-G/7209-E, SCE 5249-E, SoCalGas 6276-G, BayREN 25-E, I-REN 4-E/4-G, MCE 74-E, SoCalREN 18-E/18-G, 3C-REN 10-E/9-G were not protested.

DISCUSSION

GENERAL:

BayREN stated in their AL, "… EE PAs are not prohibited from engaging in event-based or any other IDSM activities, with the exception of providing capital incentives to customers for non-EE investments."[8]

In response to BayREN's statement, we clarify that EE multi-DER IDSM programs and frameworks proposed by PAs do not allow for event-based DR, however, PAs are not prohibited from accessing incentives or other financial compensations or financial credit for event-based DR through other proceedings. This Resolution pertains to the budget

[8] BayREN AL 25-E at 7-8.

authorized by this Resolution and D.23-06-055 and does not pertain to other funding sources for event-based DR.

Many PAs proposed to incorporate technical assistance (TA) components into proposed IDSM programs and frameworks. TA components of proposed IDSM programs and frameworks should be a collaborative and coordinated effort by the PAs to build a comprehensive customer first approach to IDSM multi-DER implementation. TA can include but should not be limited to: audits, education, project design specifications, procurement and funding support, assisting in drafting city ordinances, financial analyses, and project implementation.

In their AL, PG&E requested the following, "PG&E requests the Commission clarify that the pilot requirements from D.09-09-047 Ordering Paragraph (OP) 20 do not apply to the multi-DER program pilots governed by D.23-06-055, on the basis that the requirements from D.23-06-055 and the associated ED Guidance – and the framework proposed in this AL - sufficiently address the spirit and intent of the criteria identified in D.09-09-047 OP 20."[9] We clarify that the D.09-09-047 OP 20 requirements do not apply to these pilots, and that the parameters laid out in D.23-06-055 and the associated ED Guidance sufficiently address the spirit and intent of the D.09-09-047 criteria.[10]

FUTURE SUBMISSIONS:

Because PG&E, SCE, and SoCalGas submitted frameworks in their Tier 3 ALs and not specific programmatic details, we direct the IOUs to adhere to all applicable CPUC policies, including the third-party Tier 2 AL requirement and the program launch checklist for all non-third-party programs.[11,12]

PG&E outlined two paths for CPUC approval of new IDSM pilot programs.[13] For programs that trigger D.18-01-004 OP 2, PG&E will submit a Tier 2 AL. For programs that do not trigger D.18-01-004 OP 2, PG&E will submit a Tier 1 AL. We adopt PG&E's recommendation and require IOUs to submit a Tier 1 AL for each third-party

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[9] PG&E AL 4876-G/7209-E at 1.

[10] ED's Guidance on Integrated Demand Side Management (IDSM) Tier 3 Advice Letter Submissions from the Energy Efficiency Portfolio Administrators (PAs)

[11] *See* D.18-01-004 at OP 2.

[12] Energy Division Process Checklist to Energy Efficiency Program Administrators for Program Closures and Launches, per D.21-05-031, OP 12, dated 12/31/2021.

[13] PG&E AL 4876-G/7209-E at 6-7.

contract valued under $5M and/or with a term less than three years in duration. This Tier 1 AL requirement will sunset in 2027 and may be addressed in subsequent business cycle decisions.

BayREN, I-REN, MCE, SoCalREN, and MCE submitted program-level details on their multi-DER IDSM activities. Therefore, these PAs may begin their program activities upon the adoption of this Resolution. If these PAs wish to add additional programs or expand their programs beyond the scope described in their ALs for portfolio years 2024-2027, they shall follow the program launch checklist, which includes the submission of a Tier 2 AL.[14]

All PAs' IDSM pilot programs ALs shall describe the pilot's ex ante approach, tools and methodologies to ensure evaluability.

TOTAL RESOURCE COST & COST EFFECTIVENESS:
In their framework, PG&E proposed that the TRC cost treatment of layered incentives received by EE multi-DER program participants from other programs will be determined on a case-by-case basis for each program.[15] Subsequently, PG&E must provide more details on cost-effectiveness and the TRC in their future AL(s).

SCE proposed that the cost effectiveness of their PLS proposals be calculated using estimated load shapes and energy impacts. These load shapes will be estimated by the implementer with the assistance of SCE. They will input these values into the EE Cost Effectiveness Tool (CET) to calculate the TRC and TSB of the proposal.[16] SCE must provide more details on cost-effectiveness and TRC in their future AL(s).

Finally, SoCalGas did not mention cost-effectiveness and TRC in their AL. SoCalGas must develop and provide detailed information on their program's plan for cost-effectiveness and TRC in their subsequent AL(s).

In cases where load shapes will be used for the CET, all PAs must use, if available, established load shapes. If there is not an existing load shape available for the measure,

[14] *See* D.21-05-031 at OP 12
[15] PG&E AL 4876-G/7209-E at 21.
[16] SCE AL 5249-E at 8.

the PA should have the CPUC Database of Energy Efficiency Resources (DEER) team review and provide feedback prior to use.

EX ANTE:

Because PG&E, SCE, and SoCalGas all proposed frameworks to inform future multi-DER IDSM programs instead of proposing tangible programs, their ex-ante methodologies were also proposed broadly as to allow them to fit future specific program needs. These three PAs must file more specific ex ante methodologies in the subsequent ALs when their program details are ready.

In PG&E's AL, they requested the ability for multi-DER programs that meet the requirements for use of Normalized Metered Energy Consumption (NMEC) to instead use engineering estimates when necessary to achieve better disaggregation of impacts by DER since disaggregation is a requirement.[17] For these pilots, we find that this request is reasonable, since the use of NMEC may not be the most effective way to disaggregate the total savings into DER-specific contributions in these new multi-DER IDSM pilot programs.

REPORTING:

The California Energy Data and Reporting System (CEDARS) was not designed to capture the benefits and costs of these multi-DER IDSM programs. Therefore, at this time, we will allow the PAs to forgo reporting to CEDARS and instead report program benefits and costs in their EE Annual Reports, after discussing with the Reporting Project Coordination Group.

EX POST:

SCE and SoCalGas must further develop and provide details on their ex post plans in their subsequent ALs.

SCE states in their AL that they plan on implementing PLS interventions.[18] It is unclear how the post-intervention load shape will be developed and verified. Clarity about data collection and analysis plans supporting the estimation of ex post load shapes are a critical step in developing claims. SCE is required to show their impact methodologies and describe in detail how they will estimate post-intervention load shape in their future AL(s).

[17] PG&E AL 4876-G/7209-E at 19.
[18] SCE AL 5249-E at 3.

CONFLICT RESOLUTION:
In an effort to facilitate the integration of multi-DER IDSM programs between different proceedings, PG&E provided a Conflict Resolution framework in their AL that handles conflicts between the multi-DER IDSM program's intended design and implementation, non-EE DER proceeding rules, and PG&E's internal rules for program operations.[19] We find that this framework is helpful to understand how PG&E may need to resolve future discrepancies in rules, and we require that both SCE and SoCalGas expand on any conflict resolution protocols in their future ALs.

COMMENTS

Public Utilities Code section 311(g)(1) provides that this Resolution must be served on all parties and subject to at least 30 days public review. Any comments are due within 20 days of the date of its mailing and publication on the CPUC's website and in accordance with any instructions accompanying the notice. Section 311(g)(2) provides that this 30-day review period and 20-day comment period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day review and 20-day comment period for the draft of this resolution was neither waived nor reduced. Accordingly, this draft resolution was mailed to parties for comments, and will be placed on the CPUC's agenda no earlier than 30 days from today."

FINDINGS

1. Decision (D.) 23-06-055 allowed portfolio administrators (PAs) to submit a Tier 3 Advice Letter (AL) detailing their intended multi-distributed energy resource (multi-DER) integrated demand side management (IDSM) frameworks and programs for portfolio years 2024-2027.
2. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company (SoCalGas), San Francisco Bay Area Regional Energy Network (BayREN), Marin Clean Energy (MCE), Southern California Regional Energy Network (SoCalREN), and Tri-County Regional Energy Network (3C-REN) filed Tier 3 ALs on March 15, 2024 to establish their multi-DER IDSM frameworks or programs pursuant of D.23-06-055.

[19] PG&E AL 4876-G/7209-E at 18.

3. Inland Regional Energy Network (I-REN) filed a Tier 3 AL on March 14, 2024 to establish their multi-DER IDSM framework or program pursuant of D.23-06-055.
4. EE multi-DER IDSM programs and frameworks proposed by PAs do not allow for event-based DR. However, PAs are not prohibited from accessing incentives or other financial compensations or financial credit for event-based DR through other proceedings. This Resolution does not pertain to other avenues where event-based DR may be done.
5. D.09-09-047 OP 20 requirements do not apply to these multi-DER IDSM pilots, and the parameters laid out in D.23-06-055 and the associated ED Guidance sufficiently address the spirit and intent of the D.09-09-047 criteria.
6. PG&E, SCE, and SoCalGas submitted frameworks in their Tier 3 ALs and not specific programmatic details.
7. It is reasonable for IOUs to file a Tier 1 AL for each third-party contract valued under $5M and/or with a term less than three years in duration.
8. BayREN, I-REN, MCE, SoCalREN, and MCE submitted program-level details on their multi-DER IDSM activities.
9. PG&E proposed that the TRC cost treatment of layered incentives received by EE multi-DER program participants from other programs be determined on a case-by-case basis for each program.
10. SCE proposed that the cost effectiveness of their PLS proposals be calculated using estimated load shapes and energy impacts. These load shapes will be estimated by the implementer with the assistance of SCE. They will input these values into the EE CET to calculate the TRC and TSB of the proposal.
11. SoCalGas did not mention cost-effectiveness and TRC in their AL.
12. SCE and SoCalGas only provided high level details on their ex-post plans
13. Since PG&E, SCE, and SoCalGas all proposed frameworks to inform future multi-DER IDSM programs instead of proposing tangible programs, their ex-ante methodologies were also proposed broadly as to allow them to fit future specific program needs.
14. PG&E proposed to use engineering estimates instead of NMEC when it is necessary to achieve better disaggregation of impacts by DER.
15. CEDARS was not designed to calculate the benefits and costs of these multi-DER IDSM programs.
16. SCE stated in their AL that they plan on implementing PLS interventions.
17. PG&E and SoCalGas both expressed in their ALs that they do not anticipate any exceptions of deviations from existing policy at this time.

18. PG&E's proposed Conflict Resolution framework handles conflicts between the multi-DER IDSM program's intended design and implementation, non-EE DER proceeding rules, and PG&E's internal rules for program operations.

THEREFORE IT IS ORDERED THAT:

1. PG&E Advice Letter 4876-G/7209-E, SCE Advice Letter 5249-E, and SoCalGas Advice Letter 6276-G are approved with the modifications set forth below:
   - The IOUs shall follow all applicable CPUC policies, including the program launch checklist and third-party Tier 2 AL requirement. If the pilot program is a third-party program and falls below a $5 million budget threshold or is less than three years in duration, the IOU must file a Tier 1 AL for each third-party contract.
   - The resulting ALs for the pilot programs must provide insight into the pilot's ex-ante approach, tools and methodologies to ensure evaluability.
2. BayREN Advice Letter 25-E, I-REN Advice Letter 4-E/4-G, MCE Advice Letter 74-E, SoCal REN Advice Letter 18-E/18-G 3C-REN Advice Letter 10-E/9-G are approved with the modifications set forth below:
   - The PAs shall follow all applicable CPUC policies, including the program launch checklist.
3. In their future AL(s), PG&E must complete the following:
   - Provide additional details on cost-effectiveness and TRC.
4. The request by PG&E to use engineering estimates for these pilots instead of NMEC to achieve better disaggregation of impacts by DER is approved.
5. In their future AL(s), SCE must complete the following:
   - Provide additional details on cost-effectiveness and TRC.
   - Further develop and provide details on their ex post plans, show impact methodologies, and describe in detail how SCE will estimate post-intervention load shape.
   - Show their impact methodologies and describe in detail how they will estimate post-intervention load shape.
   - Expand on any conflict resolution protocols.
6. In their future AL(s), SoCalGas must complete the following:
   - Develop and provide detailed information on their program's plan for cost-effectiveness and TRC.
   - Further develop and provide details on their ex post plans.
   - Expand on any conflict resolution protocols.

7. In cases where load shapes will be used for the CET, if available, PAs shall use an established load shape. If there is not an existing load shape available for the measure, the PA should have the CPUC Database of Energy Efficiency Resources (DEER) team review and provide feedback prior to use.
8. For these pilots, the PAs may forgo reporting to CEDARS and instead report program benefits and costs in their EE Annual Reports.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed, and adopted at a conference of the Public Utilities Commission of the State of California held on December 5, 2024, the following Commissioners voting favorably thereon:

____

Rachel Peterson
Executive Director

APPENDIX

1. **PG&E**

Table 1. PG&E IDSM Program Details

Scope	Proposal
Program or framework proposed	Framework
Technologies	Many technologies being considered; more details in future CPUC AL(s)[20]
Program type	Pilots in Market Support segment
Relevant proceedings	A.22-05-002 et al. (Demand Response) R.20-05-012 (SGIP) R.18.12-006 (Transportation Electrification) **Please Note: R.23-12-008 is the successor proceeding and the appropriate reference** Low Carbon Fuel Standard Portfolio (LCFS): LCFS Regulation, 17 CCR § 95480 (R.18-12-006 reopened) Senate Bill 350 Standard Review Project - EV Fleet Program (EV Fleet): (A. 17-01-022)
Rules for exceptions or deviations from established CPUC policy	PG&E does not plan to seek any exemptions or deviations from CPUC rules in non-EE proceedings.[21] Each program's Implementation Plan will describe conflicts that may impact the implementation of PG&E's EE multi-DER program, and their associated resolution pathway. PG&E's proposed conflict resolution pathway[22]:

[20] PG&E AL 4876-G/7209-E at 9.
[21] PG&E AL 4876-G/7209-E at 18.
[22] *Id.*

	- For conflicts between (a) the EE multi-DER program design for non-EE DER incentives and (b) the non-EE DER proceeding rules governing the non-EE DER funding, PG&E may resolve the conflicts by modifying or ceasing to offer the non-EE DER intervention in its EE multi-DER program - For conflicts between the EE multi-DER program's intended implementation of non-EE DER incentives and PG&E's rules for programs operating within the applicable non-EE DER proceeding, and PG&E determines that its non-EE DER program rules cannot reasonably be modified to accommodate the EE multi-DER program's planned implementation of non-EE DER incentives, then the non-EE DER program rules will override PG&E's EE multi-DER program design for the applicable non-EE DER incentive. If PG&E's non EE-DER program rules can be reasonably modified at PG&E's discretion, without the need for AL approval, then PG&E may proceed with the EE multi-DER program's intended implementation of the non-EE DER incentive.
CPUC authorized funding sources and guidelines	Any EE multi-DER IDSM programs that leverage incentive funds outside of EE for non-EE DER equipment will source these funds from budgets that are authorized in their own relevant proceeding.[23] PG&E proposes that equipment rebates/incentives for non-EE DER technologies (to be funded through non-EE funding sources) follow the same definitions for rebates/incentives used in the EE proceeding and adopted in the California Standard Practice Manual for Economic Analysis of Demand-Side Programs and Projects (SPM) where rebates or incentives are payments made directly to the customer (or offset costs that would otherwise be incurred by the customer, such as in the case of Direct Install (DI) (programs).[24]

[23] PG&E AL 4876-G/7209-E at 11.
[24] PG&E AL 4876-G/7209-E at 12.

	PG&E proposes that EE funding be allowed for any program costs that meet the EE Policy Manual Version 6.0, Appendix C cost category definitions of utility administrative costs, direct implementation non-incentive (DINI) costs, incentives (for EE equipment), marketing and outreach (M&O) costs, and Evaluation, Measurement, and Verification (EM&V) costs. Any of these listed program costs would be paid for by EE funds.[25]
Approach to draw from each funding source	PG&E recommends that the appropriate cost tracking/recovery mechanism be tailored to each proposed multi-DER project based on the unique circumstances of the proposal. These details will be included in a subsequent AL. For cost tracking, PG&E proposes to leverage existing balancing accounts (BAs) for EE and non-EE DER complement (e.g., DR, battery, EV, etc.) if available. The establishment of sub-accounts would most likely be within these existing EE BAs and the BAs for the non-EE DER complement. If there are no existing BAs for the non-EE complement, then new BAs could be set up.[26] For recovery of costs, PG&E proposes to use the existing and approved rate components and related BAs. To read about PG&E's proposed reimbursement mechanism, please see section 2.1.2 below this table.

[25] PG&E AL 4876-G/7209-E at 13.
[26] PG&E AL 4876-G/7209-E at 17.

Reporting requirements (including timing)	PG&E proposes to report estimated ex ante benefits and costs of these ISDM programs in its EE annual report. PG&E proposes to exclude these programs and the associated "claims" from the CEDARS platform until two criteria are met. The criteria are[27]: (a) CEDARS and the Cost Effectiveness Tool (CET) are equipped with the functionality to properly calculate the benefits and costs for EE multi-DER programs. (b) PG&E can provide compelling evidence or rationale that its EE multi-DER programs ex ante benefits do not overlap or conflict with ex ante benefits reported to the CPUC for other non-EE DER programs. PG&E seeks to report all program ex ante benefits where possible – inclusive of non-EE DER interventions offered by the EE multi-DER program – in its annual report to demonstrate the potential of these comprehensive, integrated DER pilot programs for informational purposes. PG&E provided no sample metrics or indicators.
Procedural path for access to funding	PG&E outlined their procedural path for access to funding in a regulatory mechanism table in their AL. A re-creation of this table's relevant parts can be found below, titled "Table 2. PG&E Procedural path for access to funding".
Ex ante assumptions for EE reporting	Ex ante will be based on the specific program details. Table 3 below provides a framework for the methods they will follow. NMEC will be used when it is feasible and appropriate, but PG&E wishes to forgo using NMEC methodologies, and instead apply another ex ante methodology as noted in Table 3 below, cases

[27] PG&E AL 4876-G/7209-E at 26.

	where there may be a conflict in DER benefits reporting, and engineering estimates of disaggregated DER benefits are warranted[28]. A net-to-gross (NTG) ratio of 1.0 applicable to all multi-DER program pilot measures until EE PA multi-DER program ex post evaluation results are available to potentially inform alternative NTG assumptions.[29]
Total Resource Cost (TRC) and cost effectiveness	PG&E proposes that the TRC cost treatment of layered incentives received by EE multi-DER program participants from other programs will be determined on a case-by-case basis for each program in accordance with the SPM. The TRC cost treatment adopted will be explained in the EE annual report for the EE multi-DER program. These inputs will not be reported in CEDARS.[30] PG&E's EE multi-DER programs will attempt to collect data on incentives received by participants for overlapping DER measures from other programs.
Ex Post process	PG&E plans to conduct EM&V studies of the program pilot offerings to inform in-flight and future multi-DER programs. PG&E plans to examine program design, load impact assessment for savings assumptions validation and savings claims, coordination and impact of program and non-program incentives, and improvements to methods for making future ex ante estimates.[31]

[28] PG&E AL 4876-G/7209-E at 19.
[29] *Id.*
[30] PG&E AL 4876-G/7209-E at 21.
[31] PG&E AL 4876-G/7209-E at 27.

	PG&E will consider running embedded M&V studies (process and/or Early M&V) concurrent with program operations to (a) estimate savings and apportion them across DERS; (b) improve program design and efficiency; and (c) inform performance-based compensation, within a shorter timeframe than is possible through typical ex post evaluations. Draft M&V plans would be developed as part of the program Implementation Plans.

Further Details of PG&E's Proposal:
Reimbursement Mechanism:
In relation to a potential reimbursement mechanism in the balancing accounts, PG&E states:

"The Decision's language assumes that "the balancing accounts would be reimbursed based on rebates and incentives from other programs and proceedings, based on the rules for those other resources." However, PG&E points out that it may be possible to leverage order numbers to properly charge the EE and non-EE DER complement without the need to reimburse the EE side of the ledger. Requiring a reimbursement mechanism would be in many cases more complex, require additional tracking and create additional risk for mistakes. Although, in certain cases a reimbursement mechanism could be appropriate if the financial outlay is fully handled by the EE side of the project.[32]

[32] PG&E AL 4876-G/7209-E at 17.

Table 2. PG&E Procedural path for access to funding[33]

Multi-DER Pilot Program Operational Component		Proposed Regulatory Mechanism for Multi-DER Program Operational Components				
		EE Proceeding				Applicable Non-EE DER Proceeding
		Multi-DER Program Framework Tier 3 AL	New Program Contract Tier 2 AL if required by D.18-01-004 OP 2 (b) -OR Tier 1 AL if program does not trigger D.18-01-004 OP 2 criteria	Multi-DER Program Implementation Plan	Multi-DER Program Evaluation Plan	Service List Notice
Program Funding (from EE and non-EE Sources)	Description of general funding sources available as of March 2024 for 2024–2027 timeframe (no program-specific budgets)	X				

[33] *Id*.

	Notification to CPUC and appropriate proceeding service list(s) of intent to use specific existing, authorized non-EE incentive funding amounts in EE Multi-DER Program during 2024–2027 period		X			X
	Program-specific budget, budget limitations, and source of existing authorized funds (for EE and non-EE funds, including legacy IDSM funds)		X			

Table 3. PG&E Ex Ante Methods[34]

Ex Ante Component	Ex Ante Methods by EE Multi-DER Program Type			
	NMEC-Eligible Programs		Programs Not Eligible for NMEC	
	EE Measures	Non-EE DER Measures	EE Measures	Non-EE DER Measures
Load Modifying Impact Methodology	NMEC		Existing CPUC approved engineering methods through the EE ex ante process (i.e., custom and deemed)	Where possible, engineering methods will be used to estimate temporal load impacts to pair with temporal avoided cost profiles. Otherwise, future ex ante estimates may be informed by multi-DER program evaluation results.
TSB Reporting Granularity	Program-level impact (aggregated TSB impacts for all DER measures)		DER measure-level impact (where ex ante estimates are possible)	
TSB Estimating Tool	PG&E-vetted tool developed for multi-DER pilot. Any tools developed for multi-DER pilots may be proposed for future review and		Existing CPUC-approved engineering methods through the EE ex ante process (custom, deemed)	PG&E-vetted tool developed for multi-DER pilot(s). Any tools developed for multi-DER pilots may be proposed in the future for review

[34] PG&E AL 4876-G/7209-E at 23-24.

<table>
<tr><td></td><td colspan="2">standardization by the CEDARS/ Cost-Effectiveness Tool (CET) governance committee for use in CEDARS/CET.</td><td>will be used to estimate annual load
impacts, which will be paired with CPUC-approved EE
temporal load shapes to pair with temporal ACC profiles through the CET for TSB estimation.</td><td>and standardization by the CEDARS/CET governance committee for use in CEDARS/CET.</td></tr>
<tr><td>Baseline</td><td colspan="2">Existing conditions baseline (pre-intervention metered load)</td><td>CPUC-approved baseline depending on the measure application type, in accordance with Resolution E-4818.</td><td>Engineering estimates of preintervention existing conditions load profiles.</td></tr>
<tr><td>Effective Useful Life (EUL)</td><td>CPUC-approved EUL depending on the measure.</td><td>Engineering Estimates based on the nature of the DER intervention.</td><td>CPUC-approved EUL depending on the measure.</td><td>Engineering estimates based on the nature of the DER intervention.</td></tr>
<tr><td>TRC Calculation</td><td colspan="4">TRC Cost Benefits:
TRC benefits will include all multi-DER program avoided cost benefits based on ex ante estimates.

TRC Cost Inputs:
• All non-incentive EE multi-DER program costs
• All program-implemented DER measure (project) costs</td></tr>
</table>

	• All EE multi-DER program incentives (for both EE and non-EE measures) • Layered incentives from other programs outside of the EE proceeding, including o Incentives from PG&E DER programs within a non-EE CPUC proceeding, if applicable o Incentives from non-PG&E programs, if applicable • Increased supply costs resulting from any load shifting from peak to off-peak hours PG&E acknowledges the need to consider layered incentive costs in the TRC test but does not propose a specific layered incentive cost treatment in this advice letter. Instead, PG&E proposes the TRC cost treatment of layered incentives received from other programs by EE multi-DER program participants be determined on a case-by-case basis for each multi-DER program in accordance with the SPM.

PG&E AL Overview

PG&E proposed a framework for multi-DER IDSM pilots in the Market Support segment of EE. While many technologies are being considered, PG&E notes that more details are to come in future AL(s).

Future Submissions

PG&E proposes that they will follow two potential paths in outlining their multi-DER IDSM program-specific details prior to program implementation, depending on the size of the program[35]:

1) For programs that trigger D.18-01-004 OP 2, PG&E will submit a New Program Contract Tier 2 AL.
2) For programs that do not trigger D.18-01-004 OP 2, PG&E will submit a Tier 1 AL.

[35] PG&E AL 4876-G/7209-E at 6-7.

Total Resource Cost (TRC) & Cost Effectiveness

PG&E proposes that the TRC cost treatment of layered incentives received by EE multi-DER program participants from other programs will be determined on a case-by-case basis for each program. They also propose that the TRC cost treatment adopted will be explained in the EE annual report for the EE multi-DER program and not be reported to CEDARS.[36]

Ex Ante

PG&E states that their ex ante values will be based on specific program details but provides a framework for the methods that they will follow in their AL. PG&E notes that Normalized Metered Energy Consumption (NMEC) will be used when it is feasible and appropriate. In cases where there may be a conflict in DER benefits reporting, and engineering estimates of disaggregated DER benefits are warranted, PGE proposes to apply another ex ante methodology .[37]

Reporting

In discussion of reporting requirements for the future programs, PG&E proposes to report estimated ex ante benefits and costs in its EE annual report. They hope to exclude these programs and the associated "claims" from the California Energy Data and Reporting System (CEDARS) platform until two criteria are met. The criteria are[38]:

(1) CEDARS and the Cost Effectiveness Tool (CET) are equipped with the functionality to properly calculate the benefits and costs for EE multi-DER programs.
(2) PG&E can provide compelling evidence or rationale that its EE multi-DER programs ex ante benefits do not overlap or conflict with ex ante benefits reported to the CPUC for other non-EE DER programs.

[36] PG&E AL 4876-G/7209-E at 21.
[37] PG&E AL 4876-G/7209-E at 19.
[38] PG&E AL 4876-G/7209-E at 26.

PG&E also states that they seek to report all program ex ante benefits where possible - inclusive of non-EE DER interventions offered by the EE multi-DER program - in its annual report to demonstrate the potential of these comprehensive, integrated DER pilot programs for informational purposes.

Ex Post

PG&E notes that they plan to conduct Evaluation, Measurement and Verification (EM&V) studies of the program pilot offerings to inform in-flight and future multi-DER programs, with draft M&V plans developed as part of the program Implementation Plan.[39]

Conflict Resolution

To facilitate the integrative nature of multi-DER IDSM programs between different proceedings, PG&E provided a proposed conflict resolution pathway that handles conflicts between the multi-DER IDSM program's intended design and implementation, non-EE DER proceeding rules, and PG&E's internal rules for program operations. More details on the proposed conflict resolution pathway can be found in PG&E's AL and in the Appendix of this Resolution.[40]

[39] PG&E AL 4876-G/7209-E at 27.

[40] PG&E AL 4876-G/7209-E at 9.

2. SCE

Table 4. SCE IDSM Program Details

Scope	Proposal
Program or framework proposed	Framework
Technologies	Samples of technologies that will be pursued[41]: • Programmable Heat Pump Water Heaters (Unitary and Commercial) • Programmable Battery Storage
Program type	• EE: All sectors, downstream; market support; On-Bill Financing for eligible sectors[42] • SGIP: All eligible sectors, downstream
Relevant Proceedings	R.13-11-005 (EE) R.20-05-012 (SGIP) R.20-08-022 (Clean Energy Financing) A.20-03-004 (Energy Storage & Procurement Incentive Plan) R.18.12-006 (Transportation Electrification) - **Please Note: R.23-12-008 is the successor proceeding and the appropriate reference** R. A-19-11-003 et al. (Energy Savings Assistance) R.19-01-011 (Building Decarbonization) A.22-05-002 et al. (Demand Response)
Rules for Exceptions or Deviations from	For the purposes of this AL, SCE did not develop details for this illustrative offering.

[41] SCE AL 5249-E at 20.

[42] *Id.*

established CPUC policy	
CPUC authorized funding sources and guidelines	SCE requests shifting $12M authorized for the 2024-2027 EE business cycle to "PLS (Permanent Load Shifting) Reserve" in the Market Support segment from solicitation placeholders. As PLS measure proposals are approved, funding will shift to approved programs. Each program will be limited to $2M for the 2024-2027 EE business cycle, allowing six proposals to be developed. SCE reserves the option to reallocate PLS funds to any degree to achieve EE portfolio goals. SCE may also shift up to an additional $3M from the 2024-2027 programs to supplement high product PLS offers up to the total cap of $15M.[43]
Approach to draw from each funding source	SCE plans to ensure the projects are developed to meet both EE and SGIP reporting requirements. Heat pumps and PLS incentives will be paid for through EE R.13-11-005, while battery and PLS incentives will be paid for through SGIP R.20-05-012. Financing will be leveraged through R.20-08-022. SCE also states that heat pump incentives may also be received through R.20-05-012 when eligible.[44] Promoting battery storage will be paid for through the IDSM component of our EE Program. Direct incentives will be captured through SGIP not EE. All rules and standards from both programs apply.

[43] SCE AL 5249-E at 10.
[44] SCE AL 5249-E at 21.

	Balancing Accounts: - SCE will utilize existing Procurement Energy Efficiency Balancing Account (PEEBA) to tract new PLS activity by creating a sub-account within PEEBA to record the revenue, related expenditures, and applicable accrued interest.[45]
New methods to show stacking of costs	HPWH project costs where PLS occurs will account for additive costs for controllers within the submitted invoice. Storage and associated costs will be itemized separately to the EE technology.[46] Program costs will be managed between EE delivery and multi-DER delivery in EE Market Support. Multi-DER delivery costs will be excluded from TRC weighted program costs. Multi-DER delivery costs will be accounted for through hourly timecard reporting and accrued costs to separate contract line items.
Reporting requirements (including timing)	Programs will follow EE reporting requirements with monthly savings and expenditure reporting and quarterly claims reporting via CEDARS and annual program activities, expenditures, costs effectiveness and savings will be reported in EE Annual Report.[47]

[45] SCE AL 5249-E at 10.
[46] SCE AL 5249-E at 21.
[47] SCE AL 5249-E at 21-22.

<table>
<tr><td></td><td>Programs/Projects will also follow reporting requirements from SGIP proceedings.

Framework Sample Metrics:
kW permanent load shift
HPWH - number of units scheduled to deliver PLS
Evidence of scheduling
kW load shift value
kW permanent load reduction
kW in storage installed
Evidence of smart inverter/controller
Evidence of permanent load reduction: resources reports, images, interconnection agreements</td></tr>
<tr><td>Procedural path for access to funding</td><td>For purposes of this AL, SCE did not develop details for this illustrative offering.</td></tr>
<tr><td>Ex ante assumptions for EE reporting</td><td>Custom Methodology based on proposed program details.

Since all PLS offerings will be new EE measures, baselines and assumptions will follow existing EE measure rules.

All measurement approaches for all EE Programs will be available for creating PLS Measures and/or multi-DER projects/ programs, including Deemed, Custom, NMEC, SEM, etc.</td></tr>
<tr><td>Total Resource Cost (TRC) and cost effectiveness</td><td>The cost-effectiveness of PLS proposals will be calculated using estimated load shapes and energy impacts. These will input in the EE CET to calculate the TRC and Total System Benefits</td></tr>
</table>

	(TSB) of the proposal. The results will inform the prioritization of PLS measures with or without multi-DER budget towards the highest value projects.[48] As a PA, SCE proposes to support program implementers in developing PLS CET load shapes for measures so the EE portfolio can claim the appropriate benefits.
Ex Post process	Custom Methodology based on proposed program details Evaluation criteria may include customer participation, percentage of budget spend, TSB and market readiness.[49]

SCE AL Overview

SCE proposed a framework for multi-DER IDSM in all sectors of EE, noting specifically Downstream and Market Support, with On-Bill Financing available for eligible sectors, as well as all eligible sectors in the Self-Generation Incentive Program (SGIP), including downstream.
The IDSM framework was proposed with two objectives[50]:

(1) Develop PLS (Permanent Load Shifting) measures for non-EE technologies, with multi-DER integration as an additional but optional path, and integrate complementary programs such as EE, distributed generation, load management technologies, and
(2) Manage electric vehicle charging to address growing energy and system demands as multiple end-uses electrify. PLS measures will have forecast targets like any other EE measure.

[48] SCE AL 5249-E at 8.
[49] SCE AL 5249-E at 5.
[50] SCE AL 5249-E at 3.

SCE noted that many technologies are being considered and highlighted samples of technologies that will be pursued such as Programmable Heat Pump Water Heaters (Unitary and Commercial) and Programmable Battery Storage.

Future submissions
SCE states that specific measurement, evaluation, and reporting criteria will be proposed in SCE's multi-DER program and implementation plans in a subsequent Tier 2 AL.

TRC & Cost Effectiveness
The cost-effectiveness of PLS proposals will be calculated using estimated load shapes and energy impacts. These will input in the EE CET to calculate the TRC and Total System Benefits (TSB) of the proposal. The results will inform the prioritization of PLS measures with or without multi-DER budget towards the highest value projects.[51]

SCE proposes to support program implementers in developing PLS CET load shapes for measures so the EE portfolio can claim the appropriate benefits.

Reporting
SCE plans to ensure the projects are developed to meet both EE and SGIP reporting requirements. Programs will follow EE reporting requirements with monthly savings and expenditure reporting and quarterly claims reporting via CEDARS and annual program activities, expenditures, costs effectiveness and savings will be reported in EE Annual Report.[52] Programs and Projects will also follow reporting requirements from the SGIP proceeding.

[51] SCE AL 5249-E at 8.
[52] SCE AL 5249-E at 21-22.

3. SoCalGas

Table 5. SoCalGas IDSM Program Details

Scope	Proposal
Program or framework proposed?	Framework
Technologies	Hybrid Heating Clean Generation with DERs Energy Storage Carbon Capture Clean Energy Vehicle Technologies[53]
Program type	Pilot in Market Support Segment
Relevant Proceedings	R.13-11-005 (EE) R.12-11-005 (SGIP) **Please Note: R.20-05-012 is the successor proceeding and the appropriate reference**
Rules for exceptions or deviations from established CPUC policy	SoCalGas did not propose any exemptions or deviations from established policy.
CPUC authorized funding sources and guidelines	SoCalGas is not currently aware of any limits on the amount of non-EE funding sources for the proposed IDSM framework. As non-EE opportunities are identified and included within the framework, SoCalGas will research potential limits and address through the pilot offerings.
Approach to draw from each funding source	EE and SGIP will equally split the cost of non-incentive program activities (marketing, education, and outreach).[54] Program incentives will be funded by SGIP and EE From their own individual budgets. These incentives will be stacked by SoCalGas to reduce the customer's cost. The integration of the EE and non-EE program operations will be managed using a single source clearinghouse that will be led from within the EE program operations. This single source clearinghouse team will be called the Customer Clean Energy Integrator.[55] Once approved, SoCalGas will establish the accounting framework to track and report costs of CEIP along with its other EE program activities. SoCalGas will continue to monitor and report on its third-party and total portfolio EE expenditures through current EE program reporting activities to support compliance with the attendant financial requirements.[56] Balancing Accounts: SoCalGas plans to use EE funds for these projects and will record costs incurred for the program in the Demand Side Management Balancing Account (DSMBA). Additionally, any SGIP funds leveraged will be recorded to the Self-Generation Program Memorandum

[53] SoCalGas AL 6274-G at 4.
[54] SoCalGas AL 6274-G at 6.
[55] SoCalGas AL 6274-G at 8.
[56] SoCalGas AL 6274-G at 9.

	Account (SGPMA). SoCalGas will utilize its current accounting mechanisms to track costs to be able to identify any SGIP, or other potential non-EE program funds, which will support the CEIP Effort.[57]
Reporting requirements (including timing)	SoCalGas will report on the EE/DER program activities, including sharing of program costs and stacked incentives through its existing EE procedures. Reporting of program costs and accomplishments shall follow SoCasGas' Annual Report and True-up Annual Report process that are established for both the EE and non-EE funded portfolio and programs, respectively. Each funding resource will continue to report parameters in accordance with their respective regulatory requirements.[58]
Procedural path for access to funding	SoCalGas plans to use its EE funds from the Market Support portfolio category and the SGIP to advance technology improvements. As future programs are developed, other funding sources will be detailed in their respective Tier 2 ALs.[59]
Ex ante assumptions for EE reporting	Custom Methodology based on proposed program details.[60] SoCalGas intends to use all rebates and incentives available within the given IDSM project and unless instructed otherwise will default to applying net-to-gross (NTG) ratio of 1.0.[61]
Total Resource Cost (TRC) and cost effectiveness	Not addressed in this AL.
Ex Post process	Post analysis will be used to identify project success or lack thereof, helping to identify incentive structure or other market barriers that may be available to qualify it for increased funding for future portfolios.[62]

SoCalGas AL Overview

SoCalGas proposed a framework for multi-DER IDSM pilots in the Market Support segment of EE. In SoCalGas' AL, they propose SoCalGas's IDSM Pilot Program, which will be referred to as the SoCalGas Clean Energy Integration Program (CEIP). The goal of the CEIP program is to integrate complementary programs like EE, DR, and load management to address growing energy and systems demands as electrification increases. SoCalGas intends to achieve an increase in customer

[57] *Id.*
[58] SoCalGas AL 6274-G at 7.
[59] SoCalGas AL 6274-G at 6.
[60] SoCalGas AL 6274-G at 7.
[61] SoCalGas AL 6274-G at 7.
[62] SoCalGas AL 6274-G at 6.

awareness and participation in all available demand-side management program offerings through the securing of rebates and incentives coordinated by this multi-DER IDSM program. SoCalGas noted potential target technologies such as Hybrid eating, Clean Generation with DERs, Energy Storage, Carbon Capture, and Clean Energy Vehicle Technologies[63].

Future submissions
SoCalGas plans to use its EE funds from the Market Support portfolio category and the SGIP to advance technology improvements. As future programs are developed, other funding sources will be detailed in their respective Tier 2 ALs.[64]

Reporting
SoCalGas will report on the EE/DER program activities, including sharing of program costs and stacked incentives through its existing EE procedures.

Reporting of program costs and accomplishments shall follow SoCalGas' Annual Report and True-up Annual Report process that are established for both the EE and non-EE funded portfolio and programs, respectively. Each funding resource will continue to report parameters in accordance with their respective regulatory requirements.[65]

Ex Post
Post analysis will be used to identify project success or lack thereof, helping to identify incentive structure or other market barriers that may be available to qualify it for increased funding for future portfolios.[66]

4. BayREN

Table 6. BayREN IDSM Program Details

Scope	Proposal
Program or framework proposed	Expansion of existing programs while engaging in the creation of a framework.
Technologies	To be determined depending on market engagement.[67] Examples include:

[63] SoCalGas AL 6274-G at 4.
[64] SoCalGas AL 6274-G at 6.
[65] SoCalGas AL 6274-G at 7.
[66] SoCalGas AL 6274-G at 6.
[67] BayREN AL 25-E at 11.

	• Solar PV and thermal • EV Charging • Battery storge technologies
Program type	Technical assistance including application support, IDSM audits, marketing, education and outreach, workforce development across residential and public sectors and all applicable program offerings.[68]
Relevant Proceedings	R.13-11-005 (EE) R.20-05-012 (SGIP) General familiarization and monitoring of proceedings related to: R.19-01-011(Building Decarbonization) R.19-09-009 (Microgrids and Resiliency) R.21-06-017 (High DER Future/Grid Modernization) R.22-07-005 (Electric Demand Flexibility Rulemaking) R.23-12-008 (Transportation Electrification Policy and Infrastructure) R.22-11-013 (DER Cost Effectiveness and Data)
Reporting requirements (including timing)	Metrics related to non-resource IDSM activities will be reported via Unique Value Metrics and Market Support/Equity Metrics and Indicators as applicable and reported via BayREN's Annual Report.[69]

BayREN AL Overview

The AL submitted by BayREN proposed a framework that[70]:

- Identifies the steps needed to scale new approaches to existing programs towards a wider portfolio strategy;
- Outlines a decision-making process for directing IDSM funds to existing sectors, market segments, and delivery methods; and
- Develops an understanding of PLS opportunities within the authorized portfolio.

The goal of the outlined framework is to foster multi-DER approaches that focus on ongoing or permanent load shifting or load reduction. The two proposed outcomes

[68] BayREN AL 25-E at 8.
[69] BayREN AL 25-E at 10.
[70] BayREN AL 25-E at 5.

from BayREN include: the creation of a long-term framework for IDSM integration into BayREN's portfolio and to start integrating IDSM strategies into existing BayREN programs to test them and inform that long-term framework. BayREN plans to expand its existing residential programs (BayREN02: Multi-Family, BayREN08: Single Family) and newly approved programs (BayREN11: Public Sector Integrated Energy Services, BayREN12: Public Sector Targets Decarbonization Services) to include IDSM technical assistance.[71]

Metrics and Indicators
BayREN plans on tracking the number of local governments properties and residential properties leveraging technical assistance services to identify potential IDSM projects, the number of IDSM audits completed, and the number of referrals and project applications to other programs that support the installation of IDSM technologies.[72] BayREN will determine which DERs to prioritize based on where success is found to meet demand and improve customer satisfaction.

BayREN Concerns
In the AL, BayREN raised a concern regarding the ED Guidance. While the ED Guidance states that only non-event-based DR shall be pursued in this AL, BayREN notes that EE PAs are not prohibited from engaging in event-based or any other IDSM activities with the exception of providing capital incentives to customers for non-EE investments.[73]

5. I-REN

Table 7. I-REN Program Details

Scope	Proposal
Program or framework proposed	I-REN Technical Assistance and Strategic Energy Planning Program
Technologies	Technologies including but not limited to[74]: • Solar • Battery • EV Charging • Water Efficiency

[71] BayREN AL 25-E at 10.
[72] BayREN AL 25-E at 5-6.
[73] BayREN AL 25-E at 7-8.
[74] I-REN AL 4-E/4-G at 13.

	• Permanent Load Shifting • Demand Response
Program type	Expanding service offerings to already existing programs to include DER technical assistance, IDSM audits, education, and outreach activities
Relevant Proceedings	R.19-01-011 (Building Decarbonization) R.19-09-009 (Microgrids and Resiliency) R.20-05-012 (SGIP) R.19-09-009 (Microgrids and Resiliency) R.21-06-017 (High DER Future/Grid Modernization) R.22-07-005 (Electric Demand Flexibility Rulemaking) R.23-12-008 (Transportation Electrification Policy and Infrastructure) R.22-11-013 (DER Cost Effectiveness and Data)

I-REN AL Overview

In I-REN's AL, they envision an IDSM program providing technical assistance support to local jurisdictions in its region through climate resiliency projects. The goal of
I-REN's IDSM program will be to expand its technical assistance offerings to include non-EE DER measures. I-REN's approach to IDSM integration is based on energy audits, providing technical assistance that may indirectly facilitate DR installations or other IDSM measures. The expanded technical assistance services include comprehensive project support offerings such as, integrated DER audits, performance and design specifications, procurement support, funding and financing analyses and application support, and construction support for DER measures.[75]

I-REN does not plan on disaggregating impacts between EE and IDSM and they intend to couple EE education with other IDSM educational activities.[76]

Metrics and Indicators
I-REN will review indicator trends and growth to determine which services offered, and which specific measures installed, yield the most significant community impacts and should continue to receive budget resources in future portfolios. I-REN plans on tracking the number of agencies participating in engagement and outreach activities

[75] I-REN AL 4-E/4-G at 6.
[76] I-REN AL 4-E/4-G at 7.

(such as webinars and workshops), the number of agencies leveraging technical assistance services to identify DER projects, the number of audits completed, DER procurement support delivered, DER construction activities supported, number of agency DER projects implemented, and number of agency projects that receive DER financing and external funding support.[77] All IDSM DER services will be tracked separately from the provisions of EE services and will be reported in its Annual Report.[78]

[77] I-REN AL 4-E/4-G at 7-8.
[78] I-REN AL 4-E/4-G at 8.

6. MCE

Table 6. MCE Program Details

Scope	Proposal
Program or framework proposed	Peak Flex Market – IDSM Program is an expansion of an existing program while engaging in the creation of a framework
Technologies	Includes but is not limited to[79]: • Battery Energy Storage Systems (BESS) • Thermal Storage • EVSE • Building Automation • Behavioral, Retro-commissioning, Operational EE (BRO's)
Program type	Expansion of Peak Flex Market
Relevant Proceedings	R.13-11-055 (EE)
Ex ante assumptions for energy efficiency reporting	• Population-level NMEC control groups and approved documented NTG ratios tailored by sector.[80] • EUL/RULs of at least one year of load reduction potential. • A weighted EULs/RULs will be reported based on the technology mix of enrolled projects. • baseline will be established utilizing historical energy consumption data, weather normalization, and temporal patterns to predict energy usage in the absence of the program's intervention.[81]

[79] MCE AL 74-E at 5-6.
[80] MCE AL 74-E at 9.
[81] MCE AL 74-E at 5.

	• MCE will tie incentives to the TSB after accounting for administrative costs which will result in a cost-effective program deployment.[82]
	
	MCE proposes the tracking and reporting of the following program metrics and indicators for enrolled projects in its EE Annual Report[83]:
	• Number of enrolled residential and non-residential projects;
	• Forecasted annual load reduction out of peak hours (4pm-9pm) (kWh);
	• Forecasted program TSB ($);
	• Forecasted payments to aggregator ($);
	• Total measured load reduction out of peak hours (4pm-9pm) (kWh);
	    o Summer Months (June 1 – Oct 31)
	    o Non-Summer Months (all months excluding June 1 – October 31);
	• Program TSB to date ($);
	• Payments to aggregator to date ($);
	• Incentives to customers ($);
	• Total budget reserved ($);
	• Total budget remaining ($)

Ex Post process	• MCE will measure load reduction using sub-meter data, device level telemetry, or AMI data with population level NMEC and CalTRACK methods where applicable.[84] • Achieved TSB will be a function of electricity consumption shifted out of peak hours, climate zone, metered load shape, EUL and the ACC. • Measure cost will not be included in cost effectiveness calculations per IDSM guidelines.

82 MCE AL 74-E at 2.
83 MCE AL 74-E at 3.
84 MCE AL 74-E at 9.

MCE AL Overview

In MCE's AL, they propose adapting their existing Peak FLEXmarket program to implement a year-round IDSM program designed as a comprehensive strategy that offers demand response and load shifting for both residential and commercial customers. This evolving will incentivize aggregators with demand and load management capabilities for delivered daily load reduction during hours with high avoided cost value.[85] MCE anticipates using device level data, meter data and sub-meter data to evaluate program performance in combination with the Avoided Cost Calculator (ACC) to align payments with grid benefits and TSB value delivered. MCE states that they will be using a pay-for-performance ("P4P") structure tied to the ACC sends a price signal that prioritize DERs that achieve the greatest daily load reduction during the most valuable peak hours throughout the year.[86]

MCE plans on offering two distinct participation options for aggregators – daily load reduction or demand response. By offering two distinct participation options with no overlapping enrollment, MCE will not need to disaggregate impacts between load reduction and DR events.[87] This design maintains a separation between the program's load shifting and load reduction pathway funded through IDSM funding and the event-based DR funded through MCE's Operational Funds.

Ex Post

MCE states in their AL that they will measure load reduction using sub-meter data, device level telemetry, or AMI data with population level NMEC and CalTRACK methods where applicable.[88] They state that the achieved TSB will be a function of electricity consumption shifted out of peak hours, climate zone, metered load shape, EUL and the ACC.

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[85] MCE AL 74-E at 2.
[86] MCE AL 74-E at 3.
[87] MCE AL 74-E at 6.
[88] MCE AL 74-E at 9.

7. SoCalREN

Table 7. SoCalREN Program Details

Scope	Proposal
Program or framework proposed?	Framework to apply to previously authorized programs
Technologies	Aiming to be as inclusive as possible in terms of eligible technologies. Some DER Strategies that may be considered[89]: • Demand Response • Electric Vehicle Charging Stations • Solar Water Heating • Heat Pump Technologies • Energy Storage • Solar Photo-Voltaic
Program type	Expanding service offerings to already existing programs to include DER technical assistance, IDSM audits, education, and outreach activities targeting public, residential, commercial, and agricultural sectors.[90]
Relevant Proceedings	Will provide these details as relevant if proposing specific new programs in future Tier 2 ALs.
Approach to draw from each funding source	SoCalREN intends to work with customers on accessing multiple funding sources to achieve customers desired goals and has established an internal tracking database and invoices that separate/breakdown multiple funding sources.[91]
Reporting requirements (including timing)	SoCalREN will work to align any metrics with its Unique Value Metrics as appropriate[92]. These may include but are not limited to: • Channeled Energy • Peak Demand Savings • GHG Reductions SoCalREN will also track Community Impacts metrics, including but not limited to[93]:

[89] SoCalREN AL 18-E/18-G at 9.
[90] SoCalREN AL 18-E/18-G at 12.
[91] SoCalREN AL 18-E/18-G at 13.
[92] SoCalREN AL 18-E/18-G at 7.
[93] *Id.*

	• DAC Solar Capacity Installed • EVSE within DAC Multifamily Properties SoCalREN will include all metrics tied to the IDSM Framework within its Annual Report.

SoCalREN AL Overview

In the AL submitted by SoCalREN, they outline IDSM activities that they hope to add to existing programs, including[94]:

- DER audits in conjunction with EE audits
- Identification of applicable DER measures
- Development of a custom project proposal including measure mix, estimated impacts and benefits, ROI, and available incentives from other programs, and
- Providing ongoing technical support and coordination with complementary programs.

The goal of SoCalREN's IDSM activities are to equip customers with relevant information so that they can make informed decisions on implementing load shifting and/or reducing DER projects. SoCalREN intends to provide holistic and comprehensive solutions to customers that typically do not have sufficient access to energy efficiency and DER information and financial incentives. The strategy of the IDSM activities is to identify and deliver EE and DER projects that yield electricity and gas savings, overcome common barriers to implementation, and provide other benefits such as resiliency services. SoCalREN intends to offer technical assistance that will be responsive to changing customer needs. This technical assistance may include tailored EE and DER project recommendations based on collected facility information and support to leverage multiple programs for the customer's benefit in conjunction with education on these EE/DER technologies chosen.[95] Once this proposed framework is approved SoCalREN will establish IDSM program targets as appropriate for existing programs utilizing IDSM strategies.

[94] SoCalREN AL 18-E/18-G at 12.
[95] SoCalREN AL 18-E/18-G at 13.

Metrics and Indicators

Currently, SoCalREN does not intend to prioritize specific DERs over others. They will perform DER audits on a customer premise to provide specific recommendations that are relevant to each customer.[96] SoCalREN will continue to use deemed values and technical engineering analysis to determine energy savings and impacts between EE and other resources. A comparison method for energy savings or other characteristics of different DERs has not been developed at this time but will seek to leverage existing DER tools adopted by state agencies. SoCalREN states that metrics pertaining to the public sector will utilize historical program data, and any other sectors where the proposed framework strategies have not yet been deployed will be required to utilize any public market data that may be available.[97]

8. 3C-REN

Table 8. 3C-REN Program Details

Scope	**Proposal**
Program or framework proposed?	Framework
Technologies	3-CREN's does not plan to directly implement projects. Instead, 3-CREN will engage in education and technical assistance support. Technologies covered by technical assistance and education activities could include but are not limited to[98]: • Electric Vehicle Charging Infrastructure • Energy Storage • Smart Controls • Solar • Vehicle-to-grid technologies
Program type	Expanding existing programs; WE&T, C&S, Residential, Agriculture, and Commercial
Relevant Proceedings	R.19-01-011 (Building Decarbonization) R.19-09-009 (Microgrids and Resiliency) R.20-05-012 (SGIP)

[96] SoCalREN AL 18-E/18-G at 7.
[97] SoCalREN AL 18-E/18-G at 8.
[98] 3C-REN AL 10-E/9-G at 4.

	R.21-06-017 (High DER Future/Grid Modernization) R.22-07-005 (Electric Demand Flexibility Rulemaking) R.23-12-008 (Transportation Electrification Policy and Infrastructure) R.22-11-013 (DER Cost Effectiveness and Data)
Funding requirements	3C-REN intends to allocate IDSM funds across all its new and existing programs within the DI non-incentive cost category.[99] 3C-REN will include a list of external funding sources beyond the energy efficiency portfolio funding, if any, in its EE annual reports.[100]
Reporting requirements (including timing)	3C-REN plans to include IDSM-related educational trainings, referrals, and audits on the technologies listed above in EE annual reports starting in 2025. 3-CREN also plans to include customer engagement and implementation of IDSM recommendations in annual reports starting in 2026.[101]

3C-REN AL Overview

In 3C-REN's AL, they propose to include IDSM within its existing programs, largely focuses on technical assistance and education to achieve outcomes such as increased awareness of IDSM as well as increased capacity to explore and pursue opportunities related to DER and load shifting in combination with energy efficiency and electrification. Through its existing Residential Multifamily Program and new Energy Assurance and Agriculture Programs, 3C-REN proposes to expand upon the no-cost technical assistance (TA) already offered through those programs to provide education and technical support related to DERs. 3C-REN elaborates that technical assistance could include benchmarking, energy assessments, and referrals to complementary programs wherever possible, and project management assistance to shepherd customers through the participation process.[102] For its existing single family residential program and newly approved commercial marketplace program, 3C-REN proposes to incorporate education on DER technologies. For all its technical assistance and incentive programs (multifamily, single family and commercial incentive programs, as well as agriculture and Energy Assurance Services TA programs), 3C-REN also proposes to

[99] 3C-REN AL 10-E/9-G at 3.
[100] 3C-REN AL 10-E/9-G at 5.
[101] 3C-REN AL 10-E/9-G at 11.
[102] 3C-REN AL 10-E/9-G at 5.

provide referrals to programs that offer support or incentives for adoption of IDSM technologies and support in applying for funding to implement upgrades related to IDSM technologies.[103] Finally, 3C-REN will allocate IDSM funds to offer trainings to public and private sector building professionals on IDSM technologies through their established WE&T and C&S programs.[104]

Metrics and Indicators

3C-REN will use program performance data and qualitative feedback from implementers, partners, and customers to determine if increased budget should go towards priority DERs that achieve portfolio equity and market support. 3C-REN may also use metrics such as but not limited to, the number of local government agencies, multifamily properties and agricultural customers leveraging technical assistant services to identify IDSM projects, the number of IDSM audits completed, the number of trainings and educational opportunities related to IDSM technologies, and the number of referrals to the program.[105] 3C-REN will invest two years of data collection to establish a baseline to best reflect the above-mentioned metrics.[106] 3C-REN may establish potential targets related to public awareness, workforce development, and customer education.

[103] 3C-REN AL 10-E/9-G at 6.

[104] 3C-REN AL 10-E/9-G at 4.

[105] *Id*.

[106] 3C-REN AL 10-E/9-G at 5.