JANUARY FILINGS

STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *2024 Integrated Energy Policy Report Update (2024 IEPR Update)*	DOCKET NO. 24-IEPR-03 RE: Draft Electricity Demand Forecast Results

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE IEPR COMMISSIONER WORKSHOP ON DRAFT FORECAST RESULTS

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January 2, 2025

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CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *2024 Integrated Energy Policy Report Update (2024 IEPR Update)*	DOCKET NO. 24-IEPR-03 RE: Draft Electricity Demand Forecast Results

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE IEPR COMMISSIONER WORKSHOP ON DRAFT FORECAST RESULTS

The California Community Choice Association[1] (CalCCA) submits these comments pursuant to the *Notice of IEPR Commissioner Workshop on Draft Forecast Results*, dated November 22, 2024. During the *IEPR Commissioner Workshop on Draft Forecast Results* (the Workshop), held on Thursday, December 12, 2024, California Energy Commission (Commission) staff provided an overview of draft annual and hourly electricity demand forecast results. Additional presentations included: (1) summaries of the 2024 IEPR forecast updates; (2) a draft annual consumption, sales, and managed sales results; (3) updates and draft results for the hourly and peak electricity demand forecast for the Planning Forecast and Local Reliability Scenario; and (4) the 1-in-X year peak electricity demand results.

I. INTRODUCTION

Load forecasting is critically important to identifying California's electric grid needs. Rising costs of new resources, transmission, and distribution to interconnect loads and resources

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[1] 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.

have reduced prior excess capacity and resulted in a significant amount of 'just-in-time' build. That build results from a variety of processes impacting the addition of new generating and storage technology (primarily through the Integrated Resource Plan (IRP) process), transmission build (primarily through the California Independent System Operator Corporation (CAISO) Transmission Planning Process (TPP) driven by the IRP), and utility distribution planning processes. The need for each of these is driven by customer demand for electricity, determined through the IEPR demand forecast process. In addition, load-serving entity (LSE) obligations under California's Resource Adequacy (RA) program are driven by the IEPR demand forecast.

While all of these programs are foundational components of California's electric supply system, each functions on different time horizons which dictate their utilization of the IEPR demand forecast. The IRPs, as well as transmission and distribution planning, focus on long-term requirements. The RA program focuses on immediate grid reliability needs to ensure resources are under contract to LSEs and made available to the CAISO market to serve customer energy needs. As a result, program sensitivity to year-to-year changes in the demand forecast varies dramatically. The immediate need for RA requires near-term demand forecast accuracy to ensure reliability, and year-to-year stability to temper market shocks and potentially escalating prices that can result from unanticipated load forecast increases. In addition, unanticipated load forecast reductions can contribute to unintended early retirement of resources. On the other hand, the use of longer-term demand forecasting for new resource and grid build results in less sensitivity to year-to-year changes, but still requires accurate long-term forecast and sensitivity analysis.

As a result of the differing uses of the demand forecast by the current RA reliability structure and future resource and grid build needs, CalCCA recommends that the Commission:

- Supplant or supplement its bottom-up forecast development for long-term needs with historical top-down load information in the near-term to ensure load forecast stability for resource adequacy obligations; and

- Document the work of the Demand Analysis Working Group (DAWG) to ensure all LSEs benefit from decisions or discussions regarding certain programs and how they impact the demand forecast.

II. THE COMMISSION SHOULD SUPPLANT OR SUPPLEMENT ITS BOTTOM-UP FORECAST DEVELOPMENT FOR LONG-TERM NEEDS WITH HISTORICAL TOP-DOWN LOAD INFORMATION IN THE NEAR-TERM TO ENSURE LOAD FORECAST STABILITY FOR RA OBLIGATIONS

Given near-term impacts on RA obligations, the RA market, and resource availability from recent volatility in year-to-year demand forecasts, the Commission should supplant its "bottom-up" forecast development methodology with "top-down" historical load information to prevent the unintended consequences of such volatility. Commission staff presentations demonstrate the substantial efforts to accurately forecast energy demand through a detailed and intricate bottom-up approach. This approach takes many inputs and sews them together to arrive at the forecast for demand over the IEPR period. These inputs result from considerations regarding energy, behind-the-meter (BTM) resources, additional achievable fuel substitution, transportation electrification, and data center loads. While this detailed approach is necessary to ensure accuracy, it has proven to be subject to near-term, year-to-year volatility. As described below, it negatively and potentially inaccurately impacts LSE RA obligations, the RA market, and near-term resource availability. This bottom-up approach should be supplemented with "top-down" information such as the amount of load served by each Balancing Authority (BA) in California. The top-down analysis could include simple drivers like weather and the state of the economy, to result in a more stable near-term demand forecast.

A. Substantial and Unexpected Near-Term Increases in the IEPR Demand Forecast Creates Volatility, Scarcity, and Likely High Prices in the RA Market

Volatility in the near-term IEPR load forecast used for RA purposes has become significantly greater in recent years, as stated in CalCCA's comments on the October 2, 2024, Workshop on Forecast Use in Electricity System Planning,[2] and as shown below in Table 1. Table 1 shows the difference in the peak load forecast from the IEPR that were used in establishing the CPUC's RA requirements.

Table 1 – Forecast RA Needs 2018-2025 year-to-year changes

	Year over Year change in Forecast (MW)							
	2018	2019	2020	2021	2022	2023	2024	2025
1-in-2 RA Forecast	(636)	(223)	(314)	70	264	1,279	749	(1,192)

In 2023 and 2024, the forecast RA needs jump up significantly by 1,279 megawatts (MW) and then another 749 MW, followed by a dramatic decrease of 1,192 MW in 2025. During 2023 and 2024, the fleet of resources available to meet RA needs is very constrained, allowing the fleet to, at best, marginally meet the RA requirements. This substantial increase in RA needs during that period made resources more scarce and therefore likely more costly for customers. In addition, the ability to fully build new resources in the near-time timeframe of one to two years is simply not possible, especially to meet the needs of the increase depicted in Table 1.

B. Substantial and Unexpected Near-Term Decreases in the IEPR Demand Forecast May Contribute to Retirements of Resources Needed in Later Years

While substantial and unexpected near-term increases in the demand forecast can create volatility in RA markets and higher prices for customers, equally troubling are large decreases in need as shown in 2025. While the reduction in demand is certainly helpful in easing scarcity

[2] 24-IEPR-03, *California Community Choice Association's Comments on the Forecast in Electricity System Planning Workshop* (Oct. 16, 2024).

conditions, it has other undesirable impacts including the potential early retirement of resources. Sufficient capital and therefore incentive for the continued operation of a resource is provided by a combination of energy market revenues and contracts for capacity to meet RA. In most cases, having only one of those two funding resources will be insufficient to continue viable operation. When an unexpected near-term reduction in demand forecast occurs and LSE RA requirements therefore drop, some RA resources may not receive RA capacity contracts. The lack of contracts will in some cases cause that resource to retire. Subsequently, if the load forecast in future year increases and the build of new resources has not been sufficient to replace the retired resource, an insufficient set of resources will be available to meet RA needs in that subsequent year.

C. The Commission Should Incorporate a Top-Down Forecast into its Bottom-Up IEPR Forecast Analysis to Reduce Near-Term Year-Over-Year Volatility

To address the volatility resulting from either year-over-year significant increases or decreases in the demand forecast, the Commission should use a top-down forecast to either supplant or inform the bottom-up methodology for the near-term to temper the swings in the forecast and ensure stability in the RA obligations. The top-down approach will accomplish two important tasks. *First*, it will ensure high level forecasting is incorporated, such as the amount of load served by each BA in California, and basic drivers of energy need like weather and the state of the economy. *Second*, it can also ensure either new or potentially inaccurate inputs do not unnecessarily create volatility in the forecast. For example, the Commission staff presentation on BTM resources revealed that forecast of output from these resources has been overly optimistic.[3] The several thousand MW change in this BTM forecast will have a significant impact on demand given this dramatic reduction in staff's overall forecast.[4]

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[3] *See* 24-IEPR-03, Presentation by Alex Lonsdale, *Hourly Behind-the-Meter Distributed Generation Forecast Results* (Nov. 6, 2024), slide 12.

[4] *Ibid.*

It should be noted that the current bottom-up approach remains appropriate for long-term forecasting, while supplanting the bottom-up approach with top-down information can result in a more meaningful and consistent approach to ensuring that resources are retained to meet immediate reliability needs. In the long-term timeframe, the bottom-up approach is very helpful as it appropriately reflects new trends not adequately addressed by a historically based top-down approach. For example, large changes in load due to data center deployment or recent developments such as the increasing scale of electric transportation are difficult to predict with a top-down analysis that use historical data to predict the future.

CalCCA recommends that the Commission: (1) incorporate historical top-down information into the near-term demand forecast to reduce volatility negatively impacting RA obligations; and (2) retain the bottom-up approach to forecast demand over the long term to ensure construction of adequate resources to meet demand.

III. THE DAWG OUTPUTS SHOULD BE DOCUMENTED TO ALLOW ALL LSES TO BENEFIT FROM DECISIONS OR DISCUSSIONS REGARDING THE TREATMENT OF CERTAIN PROGRAMS IN THE DEMAND FORECAST

CalCCA appreciates the work of the DAWG, which allows the opportunity for LSEs to discuss with Commission staff inputs to demand forecasting. This work should continue as it provides Commission staff insight into new and unique LSE programs and how those programs may impact the demand forecast and allows staff to explain in detail its forecasting methodologies. Given not all LSEs have sufficient staff to attend the DAWG meetings or create their own library of information that has been examined, CalCCA requests that the Commission maintain documentation of discussions at the DAWG meetings to inform potential future adjustments to load forecasts. This documentation should be updated with each IEPR cycle reflecting the current approach to each forecast component. By doing so, the document will maintain in one location the history of practices used to establish load forecasts including the rationale behind such changes. In addition, LSEs can benefit from documentation and knowledge regarding how specific programs, in comparison to their own existing or future programs, are treated in the demand forecast.

IV. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments herein and looks forward to an ongoing dialogue with the Commission.

Respectfully submitted,

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Director of Regulatory Affairs and
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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

January 2, 2025

DOCKETED	
Docket Number:	21-OIR-01
Project Title:	Rulemaking to Amend Regulations Governing the Power Source Disclosure Program
TN #:	260889
Document Title:	21-OIR-01 CalCCA Comments on PSDP Revisions 01 03 25
Description:	21-OIR-01 CalCCA Comments on PSDP Revisions 01 03 25
Filer:	Shawn-Dai Linderman
Organization:	CALIFORNIA COMMUNITY CHOICE ASSOCIATION
Submitter Role:	Intervenor
Submission Date:	1/3/2025 2:48:20 PM
Docketed Date:	1/3/2025

STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *Rulemaking to Amend Regulations Governing the Power Source Disclosure Program*	DOCKET NO. 21-OIR-01 RE: Power Source Disclosure Program

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE 15-DAY PROPOSED REVISIONS TO THE REGULATIONS GOVERNING THE POWER SOURCE DISCLOSURE PROGRAM

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January 3, 2025

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IN THE MATTER OF: *Rulemaking to Amend Regulations Governing the Power Source Disclosure Program*	DOCKET NO. 21-OIR-01 RE: Power Source Disclosure Program

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE 15-DAY PROPOSED REVISIONS TO THE REGULATIONS GOVERNING THE POWER SOURCE DISCLOSURE PROGRAM

The California Community Choice Association[1] (CalCCA) submits these comments pursuant to the *Revised Notice of Availability and Opportunity to Comment, 15-Day Public Comment Period, Proposed Revisions to the Rulemaking to Amend Regulations Governing the Power Source Disclosure Program* (Revised Notice), dated December 9, 2024.

I. INTRODUCTION

The Power Source Disclosure (PSD) program was first established by Senate Bill (SB) 1305[2] in 1997, adding sections 398.1 through 398.5 to the California Public Utilities Code.[3] On May 17, 2024, the California Energy Commission (Commission) issued proposed amendments to its PSD regulations to incorporate new legislation – Assembly Bill (AB) 242[4] establishing

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1 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.

2 SB 1305 (Figueroa, Ch. 796, Stats. 1997).

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

4 AB 242 (Holden, Ch. 228, Stats. 2021).

deadlines for the Power Content Label (PCL), and SB 1158[5] adding the reporting of hourly data in addition to the current requirements to report calendar year data.[6] It also proposed other changes to the regulations to further clarify the PSD and PCL requirements, and ensure accuracy and consistency.[7] The Commission issued a second set of proposed amendments on October 4, 2024, proposing additional changes including clarifications to the timing of loss-adjusted load reporting, the source of the estimated losses, modifications to the descriptions of unspecified power, and other changes. The amendments issued on December 9, 2024 (Amendments), provide further detail, guidance, and clarifications on these topics.

CalCCA appreciates the continuing opportunity to provide input in this docket and makes five recommendations regarding the Amendments. *First*, if the regulations are adopted after January 1, 2025, but before January 1, 2026, the Commission should delay the calendar year reporting of losses to 2027 to ensure new reporting requirements only apply prospectively.

Second, the Commission should require the publication of default statewide loss factors in advance of the procurement year rather than in advance of the "reporting period" to avoid retail sellers having to estimate the losses for which to procure in any year.

Third, the Commission should clarify that "estimated losses" means "total estimated losses" to remove ambiguity and clarify that losses are calculated on a statewide level for all resources rather than for each retail seller based on the resources they procure. Basing the loss factor on United States Energy Information Administration (EIA) *statewide* factors rather than

5 SB 1158 (Becker, Ch. 367, Stats. 2022).

6 Prior to opening the current formal rulemaking to incorporate SB 242 and SB 1158, the Commission issued two sets of pre-rulemaking amendments on September 20, 2023, and January 31, 2024, and on which parties, including CalCCA, provided comments. *See* Docket 21-OIR-01.

7 Docket 21-OIR-01, *Initial Statement of Reasons + Economic Analysis* (May 17, 2024), at 1-2.

factors applicable to each retail seller will provide statewide, stable values, and enhance load-serving entities' (LSE) ability to anticipate needed procurement.

Fourth, the Commission should modify the definition of "unspecified" power to provide greater clarity about the sources of unspecified power. The Commission should revert back to the unspecified power definition utilized earlier in this rulemaking of "primarily fossil fuels but may include other sources." In the alternative, the unspecified power definition should be clarified to: (1) only require the reporting of fossil fuels or renewables and other zero-carbon resources, whichever group is greater, on a prospective basis; (2) state that *the Commission* will provide the calculations of primary and secondary resource group percentages; and (3) define "secondary resource group" in section 1393.1(l)(3).

Finally, the Commission should issue revised templates as soon as possible prior to the procurement period, and/or with any revised regulations to allow LSEs to anticipate how the proposed regulations translate into reporting requirements.

Accordingly, the Commission should:

- Begin calendar-year loss-adjusted load reporting on January 1, 2027, if the regulations are adopted after January 1, 2025, but before January 1, 2026;
- Require publication of default statewide loss factors in advance of the procurement year rather than only prior to the "reporting period";
- Modify "estimated losses" referenced in section 1392(a)(8)(B) to "total estimated losses" to clarify that the Commission will publish losses on a statewide level for all resources rather than on a retail seller level;
- Simplify or modify the definition and explanation of "unspecified" power to provide greater clarity about the sources of unspecified power; and
- Issue revised templates as soon as possible prior to the procurement period.

II. CALENDAR-YEAR LOSS-ADJUSTED LOAD REPORTING SHOULD BEGIN ON JANUARY 1, 2027, IF THE REGULATIONS ARE ADOPTED AFTER JANUARY 1, 2025, BUT BEFORE JANUARY 1, 2026

Throughout the proposed regulations, the Commission applies requirements for retail sellers to report calendar-year loss-adjusted load beginning on January 1, 2026.[8] CalCCA continues to applaud the Commission for amending the start of these requirements to January 1, 2026, for the reasons set forth in CalCCA's July 3, 2024, Comments.[9] Were the regulations adopted in advance of 2025, these revisions would have prevented the inequitable and retroactive application of the calendar year loss reporting requirement in 2025 for procurement already complete for 2024, and allowed retail sellers adequate opportunity to adapt to the new requirement.

Given issuance of the Amendments, it now appears the revised regulations will not be adopted until sometime in 2025. Therefore, the Commission should further delay the requirement until the next "reporting period" (i.e., 2027 for calendar year 2026) so that the regulation requirements are only applied prospectively. Otherwise, retail sellers will not know for certain the requirements that will be applied during their procurement for 2025. Understanding procurement requirements and reporting is a key factor affecting those procurement and optimization decisions. To the extent adoption of the regulations occurs beyond January 1, 2025, but prior to January 1, 2026, the Commission should further delay the calendar year reporting on losses associated with retail load until 2027 for the procurement year 2026.

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8 *See, e.g.,* Amendments §§ 1393(b)(2)(B), 1393.1(a)(3)), 1393.1(c), 1393.1(c)(2)(A)-(B), and 1393.1(c)(7).

9 *California Community Choice Association's Comments on Proposed Amendments to Power Source Disclosure Program Regulations,* Docket 21-OIR-01 (July 3, 2024) (CalCCA July 2024 Comments).

In addition, the Commission should revise section 1393.1(a)(3) for clarity. The Amendments modify section 1393.1(a)(3) as follows:

> The Energy Commission shall provide fuel mix and GHG emissions intensity of **~~California's total statewide retail electricity sales~~** **total California loss-adjusted load** for inclusion on the power content label. Beginning January 1, 2026, the Energy Commission shall instead provide the fuel mix and GHG emissions intensity of California's total loss-adjusted load for inclusion on the power content label.[10]

This change appears to result in either: (1) repeating the same requirement in both sentences of section 1393.1(a)(3); or (2) inadvertently requiring loss-adjusted load reporting in advance on January 1, 2026. To clarify the intent of the Amendments and avoid retroactive rulemaking, the Commission should revise the regulations to remove the first sentence as follows:

> **~~The Energy Commission shall provide fuel mix and GHG emissions intensity of California's total statewide retail electricity sales total California loss-adjusted load for inclusion on the power content label.~~** Beginning January 1, **~~2026~~** **2027**, the Energy Commission shall **~~instead~~** provide the fuel mix and GHG emissions intensity of California's total loss-adjusted load for inclusion on the power content label.[11]

III. THE COMMISSION SHOULD PUBLISH DEFAULT STATEWIDE LOSS FACTORS IN ADVANCE OF THE PROCUREMENT YEAR RATHER THAN THE "REPORTING PERIOD"

The Amendments modify section 1393.2(a)(8)(B) to add additional detail on the default loss factors that will be calculated and provided annually by Commission staff, stating:

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10 As stated in the Amendments, "[t]he proposed amendments to the existing PSD regulations that were made public in the initial express terms in the NOPA from May 17, 2024, and in the second version of the express terms in the 45-Day Notice from October 4, 2024, are shown in strike through to indicate deletions and underline to indicate additions. Additional amendments in this third version of the express terms as proposed with this 15-Day Revised Notice from December 9, 2024, are **bolded** and shown in **double strikethrough** for deletions and **double underline** for additions."

11 CalCCA's recommended revisions in **~~bold strikethrough~~** and **bold underline**.

> The CEC shall publish default statewide loss factors for specified in-state resources, specified imports, and unspecified power, as well as the underlying calculations, prior to the reporting period each year.[12]

CalCCA interprets the "reporting period" as the year retail sellers submit their PSDs, and not the calendar year with the data of interest (i.e., the procurement year). Assuming this interpretation is correct, the Amendments will result in uncertainty for retail sellers who must procure without knowing the amount of losses for which they will need to procure. The Commission should, therefore, modify the regulations to publish the default statewide loss factors in advance of the procurement period (i.e., the year retail sellers need to procure to cover losses in addition to their portfolio procurement). For example, a reporting period in 2027 that reports 2026 data will require the publication of loss factors using the most readily available data sometime in 2025. Doing so will ensure procurement requirements are clear, and that retail sellers do not have to estimate a portion of their procurement requirements for an uncertain amount of losses.

IV. "ESTIMATED LOSSES" REFERENCED IN SECTION 1392(A)(8)(B) SHOULD BE MODIFIED TO "TOTAL ESTIMATED LOSSES" TO CLARIFY THAT THE COMMISSION WILL PUBLISH LOSSES ON A STATEWIDE LEVEL FOR ALL RESOURCES RATHER THAN ON A RETAIL SELLER LEVEL

The Amendments also modify section 1393.2(a)(8)(B) to state that loss factors shall be based on "estimated" losses divided by the total energy disposition reported in the most recent final EIA "statewide" data.[13] CalCCA supports the Commission using the EIA data source for accurate loss factor calculations for both the calendar year and hourly reporting. While CalCCA's interpretation of the Amendments is that losses are calculated at a statewide level for all resources rather than for each retail seller based on the resources they procure, the term "estimated" results in a lack of clarity. The Commission should therefore clarify that "estimated losses" means "*<u>total</u>*

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12 Amendments § 1393.2(a)(8)(B) (emphasis added).

13 *See* Amendments § 1393.2(a)(8)(B).

estimated losses" to remove ambiguity and clarify that losses are calculated on a statewide level for all resources rather than for each retail seller based on the resources they procure.

The Commission's framework for calculating losses associated with retail sales, including basing the loss factor not on each retail seller but on EIA statewide factors for specified resources and unspecified power, will provide statewide, stable values. The framework will also enhance LSEs' ability to anticipate needed procurement. The Commission should therefore clarify its intent to calculate *statewide* values by modifying the term "estimated" losses to "total estimated" losses in section 1393.2(a)(8)(B).

V. THE AMENDMENTS IMPROVE THE DEFINITION AND EXPLANATION OF "UNSPECIFIED" POWER, BUT SHOULD BE MODIFIED TO CLARIFY THE SOURCES OF UNSPECIFIED POWER

CalCCA continues to recommend adoption of the parenthetical in the January 31, 2024 mock-up of PSD amendments describing "Unspecified Power" as "primarily fossil fuel generation but may include other resources."[14] The May 17, 2024 amendments, however, reverted back to a parenthetical description of "Unspecified Power" as "(primarily fossil fuels)."[15] The January 31, 2024, mock-up would appropriately acknowledge that unspecified power is primarily from fossil fuels but also includes other (including renewable) resources to ensure consumers are not misled.

If the Commission decides not to revert back to the January 31, 2024, parenthetical to describe "Unspecified Power," it should adopt the proposal in the Amendments which is more

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14 *See* Docket 21-OIR-01, *Summary of Changes and FAQs,* Fig. 1, at 9 (Jan. 31, 2024) (emphasis added): https://efiling.energy.ca.gov/GetDocument.aspx?tn=254272&DocumentContentId=89637; *see* CalCCA July 2024 Comments at 15 (recommending adoption of the January 31, 2024 mock-up with the parenthetical description of "Unspecified Power"); *accord California Community Choice Association's Comments on the Revised Notice of Availability and Opportunity to Comment on Proposed Revisions to the Rulemaking to Amend Regulations Governing the Power Source Disclosure Program* (Nov. 19, 2024) at 5-6 (continuing to recommend adoption of the January 31, 2024 mock-up): https://efiling.energy.ca.gov/GetDocument.aspx?tn=260165&DocumentContentId=96398. CalCCA November 19, 2024 Comments.

15 *See* Docket 21-OIR-01, *Express Terms* (May 17, 2024) § 1393.1(c)(1)(j): https://efiling.energy.ca.gov/GetDocument.aspx?tn=256446-3&DocumentContentId=92270.

complicated than CalCCA's preferred approach but does improve the definition. The Amendments remove the phrase "is derived primarily from natural gas and other fossil fuels" from the definition and instead identify whether unspecified power is provided *primarily* by fossil fuels or renewables and other zero-carbon resources.[16] Further, the Amendments require that:

> [b]eginning in 2026, the annotation of unspecified power shall include the *percentage* of unspecified power provided by either "Fossil Fuels" or "Renewables and Zero-Carbon ~~Zero Carbon~~ Resources" as those groups are described in 1393.1(c)(2), *whichever group was greater for the previous year*.[17]

The Amendments also require an annotation stating that:

> "Unspecified power is electricity purchased from a genericized pool on the open market." [This footnote shall also provide the *percentage* of the secondary resource group, as specified under Section 1393.1(c)(2)(A)-(B), serving unspecified power in the previous year].[18]

If the Commission requires the reporting of *whichever group of unspecified power sources is greater*, the Amendments must be modified in two ways to ensure the sources are calculated accurately and communicated clearly.

First, the Commission should add language to the Amendments that clarifies that the Commission, and not retail sellers, will calculate the percentage of unspecified power that came from fossil fuels versus renewable/zero-carbon resources. It should also clarify what data will be used and how it will be used to determine the primary source and when the calculations and percentages will be provided. This clarification is necessary because retail sellers do not have the information necessary to perform these calculations on their own. A transparent calculation

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16 Amendments § 1393.1(c)(7).

17 *Id.* § 1393.1(c)(7) (emphasis added).

18 *Id.* § 1393.1(l)(3) (emphasis added).

performed by the Commission will ensure retail sellers are confident that the information they are required to report is accurate.

Second, while CalCCA supports the requirement of the provision of the percentage of the "secondary resource group" in section 1393.1(l)(3), the Commission should clarify the definition of "secondary resource group" in "Secondary resource group" appears to refer to either renewables and zero-carbon resources as defined in section 1393.1(c)(2)(A) or fossil fuels as defined in section 1393.1(c)(2)(A), whichever group was not "greater for the previous year" as defined in section 1393.1(c)(7). To make this clarification, the Commission should clarify the term "secondary resource group, as specified under section 1393.1(c)(2)(A)-(B)" to "secondary resource group, *defined as either renewables and zero-carbon resources or fossil fuels* as specified under section 1393.1(c)(2)(A)-(B), whichever group was lesser for the previous year."

VI. THE COMMISSION SHOULD ISSUE REVISED TEMPLATES AS SOON AS POSSIBLE PRIOR TO THE FIRST PROCUREMENT PERIOD UNDER THE NEW REGULATIONS

CalCCA greatly appreciates the Commission's timely issuance of revised templates following the second set of proposed amendments on October 4, 2024.[19] The Commission should revise and publish templates to reflect the Amendments (and any subsequent revisions) prior to the first procurement period following the adoption of the proposed regulations. Revised templates are needed to allow LSEs to see how the proposed regulations translate into reporting requirements.

[19] *See* Docket 21-OIR-01, *2026 PCL Template*, *2028 Consolidated Reporting Template*, *2025 PCL Template*, and *2026 Annual Reporting Template* (Nov. 11, 2024): https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-OIR-01.

VII. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments herein.

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

January 3, 2025

California Community Choice Association

SUBMITTED 01/08/2025, 01:08 PM

Contact
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1. **Please provide a summary of your organization's general comments on the initial meeting and working group for topics related to bid cost recovery (BCR) provisions for energy storage, default energy bid (DEB) enhancements, and outage management system (OMS) enhancements.**

   The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO) initial meeting of the Storage Design and Modeling working group. In summary, these comments support the CAISO's preliminary scope and schedule, including beginning the initiative by addressing the BCR, DEB, and OMS topics.

2. **Please provide your organization's comments regarding the topics included in the tentative scope presented during the initial meeting, the topic groups, and the prioritization of issues within the topic groups.**

   CalCCA supports the topics included in the tentative scope and agrees with beginning the initiative with the BCR, DEB, and OMS topics. CalCCA's priorities in this initiative include: (1) BCR redesign and OMS enhancements as discussed in section 4 below; and (2) nonlinearity at high and low states of charge (SOC), SOC definition and the calculation, and biddable SOC participation pathway as discussed in section 5 below.

3. **Please provide your organization's comments regarding the tentative timeline presented during the initial meeting, the structure and timing of the meetings envisioned, and the overall tentative pace of the initiative.**

   CalCCA supports the tentative timeline, structure, and overall pace of the initiative.

4. **Please provide your organization's comments regarding the issues presented within Topic Group 1: BCR, DEB, & OMS Topics. Please note if additional issues should be considered as part of this topic group, including whether issues presented as part of other topic groups should be considered in this topic group.**

   In November 2024, the CAISO Board of Governors and Western Energy Markets Governing Body approved a solution developed in the BCR and DEB Enhancements initiative aimed at preventing unwarranted BCR payments to storage resources. As a continuation of that effort, CalCCA supports conducting a more holistic exploration of when storage should receive BCR payments. As a starting point, this initiative should follow the Department of Market Monitoring's recommendation to "thoroughly assess drivers of BCR under the current design"[1] and "clearly identify where battery BCR is warranted and where it is not."[2]

   CalCCA also supports the CAISO enhancing OMS to align with storage outages. As part of this effort, the CAISO must coordinate this initiative with the Resource Adequacy Modeling and Program Design (RAMPD) initiative. The RAMPD initiative is in the process of developing an unforced capacity (UCAP) framework for storage resource adequacy counting. A key part of developing a UCAP framework will be determining which types of outages will count toward a resource's forced outage rate for UCAP purposes. Current outage types that storage resources must use to report their outages likely do not accurately reflect reasons for unavailability and may result in inaccurate UCAP calculations if they are not clarified. As the CAISO enhances OMS functionality to adequately support outage submissions for storage assets, the CAISO should evaluate the need to update outage reporting and definitions in coordination with the RAMPD initiative. This will support the future

UCAP design by ensuring outage types accurately reflect the reasons for unavailability and whether different outage types should apply to a UCAP calculation.

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[1] DMM Presentation at 2.

[2] *Id.* at 7.

5. Please provide your organization's comments regarding the issues presented within Topic Group 2: State-of-Charge (SOC) Management Topics. Please note if additional issues should be considered as part of this topic group, including whether issues presented as part of other topic groups should be considered in this topic group.

CalCCA supports examining how to enhance SOC management in this initiative, and provides the following recommendations for that examination. *First*, this initiative should consider how to reflect the impact of nonlinearity on storage resources' charge and discharge capabilities at high and low SOC levels. *Second*, this initiative should seek to enhance the SOC definition and calculation to ensure resource constraints are adequately reflected in the market. *Third*, this initiative should explore a biddable SOC market participation pathway to allow energy storage resources to have charge and discharge bids in relation to their SOC.

6. Please provide your organization's comments regarding the issues presented within Topic Group 3: Distribution-level & Paired Resources Topics. Please note if additional issues should be considered as part of this topic group, including whether issues presented as part of other topic groups should be considered in this topic group.

CalCCA has no comments at this time.

7. Please provide your organization's comments regarding the foundational understanding of the matters discussed during the working group on topics related to bid cost recovery (BCR) provisions for energy storage, default energy bid (DEB) enhancements, and outage management system (OMS) enhancements.

See response in Section 4.

8. Please provide your organization's comments regarding the presentation made by the Department of Market Monitoring (DMM).

See response in Section 4.

9. Please provide your organization's comments regarding the presentation made by Pacific Gas & Electric (PG&E).

CalCCA has no comments at this time.

10. Please provide your organization's comments regarding the presentation made by Vistra Corp (Vistra).

CalCCA has no comments at this time.

11. Market participants: Please note if your organization would be interested in volunteering to co-facilitate future working groups within this initiative.

CalCCA is not interested in co-facilitating future working group meetings at this time.

12. Please provide any additional comments, feedback, or examples regarding the initial meeting and workshop. You may upload documents, examples, or data using the "Attachments" field below.

CalCCA has no additional comments at this time.

January 9, 2025

California Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

Via email to EDTariffUnit@cpuc.ca.gov

RE: MCE Response to PG&E Advice Letter to Update the Capacity Bidding Program to Enable Participation By Customers Required to Join a Demand Response Program.

Dear Energy Division Tariff Unit

Pursuant to Rule 7.4.1 of the California Public Utilities Commission's ("CPUC" or "Commission") General Order 96-B, Marin Clean Energy ("MCE") hereby submits the following timely Response to Pacific Gas & Electric ("PG&E") Advice Letter ("AL") to Update the Capacity Bidding Program to Enable Participation By Customers Required to Join a Demand Response ("DR") Program ("AL 7458-E") submitted on December 20, 2024.

MCE supports PG&E's proposed updates to its Capacity Bidding Program ("CBP") to provide new pathways for Self-Generation Incentive program ("SGIP") customers' self-enrollment that satisfy the qualified DR program requirements of Decision ("D.") 24-03-071. MCE welcomes a workable pathway for unbundled community choice aggregator ("CCA") customers to access SGIP. MCE submits one note of clarification for the Commission on the 10-year enrollment requirement that describes a participating customer's ability to disenroll from CBP and enroll in other qualified DR programs as they become available.

I. BACKGROUND

PG&E submitted AL 7458-E on December 20, 2024, proposing updates to its CBP's customer participation requirements to allow direct enrollment for residential customers that meet the following criteria:

"(a) Customers are required to participate in a Demand Response (DR) program as a condition of receiving incentives or rebates, and

(b) Customers cannot find an Aggregator to support their participation in a DR program."[1]

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[1] PG&E AL 7458-E, p. 1.

II. DISCUSSION

MCE Supports PG&E's Proposal to Expand SGIP Access for Unbundled CCA Customers

MCE supports PG&E's proposal to update its CBP to allow more ratepayers, including unbundled CCA customers, to access SGIP following D.24-03-71's qualified DR program enrollment requirement.[2] MCE along with Joint CCAs and other stakeholders supported SGIP's qualified DR program enrollment requirement while simultaneously expressing concerns that the requirement as written could place challenging barriers for unbundled CCA customers especially.[3] The programs presently listed in Appendix E of D.24-03-71 are not available or accessible to CCA customers.[4] Since the adoption of D.24-03-071, MCE has received inquiries from its customers considering opting out of CCA service and returning to PG&E's bundled service in order to hopefully access SGIP incentives.[5] MCE observes its understanding of SGIP barriers for CCA customers is consistent with PG&E's submission that, "Presently, 700+ customers are in the SGIP enrollment queue, awaiting a suitable DR program to meet participation requirements and receive their SGIP incentives."[6] MCE appreciates PG&E's thoughtful proposal to update its CBP in a manner that ensures compliance with D.24-03-071 and access to qualified DR programs for ratepayers including CCA customers. MCE believes PG&E proposed the appropriate balance of updates to its CBP to allow a viable pathway for customers to enroll in a qualified DR program and subsequently receive an SGIP incentive.

MCE Requests the Commission and PG&E Clarify SGIP's 10-Year Qualified DR program Enrollment Requirement Allows Customers to Switch Among Qualified Programs

As stated above, MCE supports the Commission adopting PG&E's AL 7458-E. MCE requests the Commission clarify in its disposition that the referenced 10-year qualified DR program enrollment requirement[7] allows customers to switch enrollment among qualified programs as they become available. PG&E references the 10-year enrollment requirement from D.24-03-071[8] in its *Redlined CBP Tariff* stating, "SGIP customers enrolled in CBP must meet the minimum 10-year Demand Response enrollment requirement."[9]

MCE submits PG&E is referring to D.24-03-071's requirement:

"Enrollment and participation in a qualified DR program must be maintained for a project's 10-year permanency period. The SGIP participant may disenroll from an approved qualified DR

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[2] D.24-03-071, OP 21, p. 102.
[3] Joint CCA Opening Comments on Proposed Decision, February 22, 2024, pp. 2-4; Joint CCA Response to Application for Rehearing of Decision 24-03-071, May 6, 2024, pp. 3-5; Joint CCA Response to SCE AL 5347-E, pp. 1-4.
[4] Joint CCA Response to SCE AL 5347-E, pp. 3-4.
[5] Ibid.
[6] PG&E AL 7458-E, p. 4.
[7] PG&E AL 7458-E, Attachment A, p. 1.
[8] D.24-03-071, p. 75.
[9] Ibid.

program to join another approved DR program but must always be enrolled in a SGIP qualified DR program."[10]

Customers unfamiliar with the complex intricacies of SGIP may misinterpret the text of this requirement to mean they must enroll in CBP exclusively for 10-years. To avoid any potential customer confusion for dual CBP and SGIP participants, MCE requests the Commission and PG&E in its communications to enrolled customers note a customer's ability to switch enrollment among qualified DR programs. MCE plans to submit its load flexibility Peak Flex Market program[11] (formerly Peak FLEXmarket program) to the Commission for inclusion on *Appendix E – SGIP-Required Demand Response Programs*. MCE requests the Commission clarify the 10-year enrollment requirement so customers can make informed decisions on the qualified DR program that best suits their individual needs.

III. CONCLUSION

MCE respectfully submits this Response in support of PG&E AL 7458-E. MCE requests clarification of the 10-year enrollment requirement. MCE looks forward to continuing to work with the Commission and all stakeholders to expand DR program offerings and access to SGIP incentives.

/s/ Wade Stano

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cc: Service Lists for A.22-05-002; R.20-05-012.
Leuwam Tesfai, Deputy Executive Director, Energy & Climate Policy, Energy Division, CPUC.
Sidney Bob Dietz II, Director, Regulatory Relations, PG&E.
Megan Lawson, PG&E.
Tariff Unit, CPUC.

DATED: January 9, 2025.

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[10] D.24-03-071, p. 75.

[11] MCE, Peak Flex Market program, available at: https://mcecleanenergy.org/peak-flex-market. MCE's Peak Flex Market program provides incentives based on the CAISO market price for participants to shift their energy usage when the grid is most constrained.

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

Order Instituting Rulemaking to Implement Senate Bill 520 and Address Other Matters Related to Provider of Last Resort.	R.21-03-011

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THRESHOLD QUESTIONS**

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Counsel for California Community Choice Association

January 10, 2025

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SUMMARY OF RECOMMENDATIONS

- The Commission should move forward with establishing the framework for non-IOU LSE POLR service regardless of current interest among existing POLRs or non-IOU LSEs in transferring POLR service from an existing POLR to a non-IOU LSE POLR;

- The Commission's framework for non-IOU LSE POLR service should acknowledge that the Commission's regulatory authority over a non-IOU LSE POLR is limited to only the non-IOU LSE's POLR-specific services. Limiting the Commission's jurisdiction in this way will faithfully implement the text of California Public Utilities Code sections 216(a)(2) and 387(j), and will harmonize the oversight over a non-IOU LSE POLR with the Commission's existing, limited jurisdiction over non-IOUs;

- The Commission should provide a non-IOU POLR with the same forms of cost recovery now available to existing IOU POLRs unless and until there is a demonstration those existing forms of cost recovery will fail to make a non-IOU POLR whole for its role of serving returned customers. Such cost recovery should follow the same methodologies set forth in the POLR Phase 1 Decision, including requiring entities being served by the non-IOU POLR to post a FSR and pay re-entry fees; and

- To ensure the non-IOU POLR can fulfill its core POLR function while awaiting receipt of any owed re-entry fees, the Commission should require any non-IOU POLR to: (1) establish it has sufficient liquidity (45 days liquidity on hand) to provide energy service to the entire customer base of the largest LSE in its proposed POLR service area for one month's time; and (2) have an IG credit rating.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 520 and Address Other Matters Related to Provider of Last Resort.	R.21-03-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THRESHOLD QUESTIONS

The California Community Choice Association[1] (CalCCA) submits these comments on threshold questions pursuant to the October 24, 2024, *Assigned Commissioner's Phase 2 Scoping Memo and Ruling*[2] (Ruling). The Ruling seeks comment on 11 Threshold Questions (and subparts). CalCCA provides the following initial comments on those Threshold Questions.

I. INTRODUCTION

Senate Bill (SB) 520 enacted California Public Utilities Code[3] section 387 and amended section 216, requiring the California Public Utilities Commission (Commission) to develop rules and regulations for a Provider of Last Resort (POLR) should a retail electric provider fail.[4] Phase 1 of this proceeding established such rules for investor-owned utilities (IOU) serving as the

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[1] 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.

[2] Rulemaking (R.) 21-03-011, Order Instituting Rulemaking to Implement Senate Bill 520 and Address Other Matters Related to Provider of Last Resort, *Assigned Commissioner's Phase 2 Scoping Memo and Ruling* (Oct. 24, 2024).

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

[4] SB 520 (Stats. 2019, Ch. 408).

POLR.[5] Section 387 also requires the Commission to develop rules and regulations allowing a load-serving entity (LSE) other than an IOU, such as a community choice aggregator (CCA) or electric service provider (ESP), to serve as a POLR (referred to in statute and here as a Designated POLR), which is set to be accomplished in Phase 2 of this proceeding. Despite the Threshold Questions concerning "interest" by IOUs and non-IOU LSEs in a Designated POLR, the Commission must fulfill its statutory obligation and set forth a reasonable pathway (Designated POLR Framework) through which a non-IOU LSE can become a Designated POLR. The Commission should do so even if there is currently no or limited interest among existing POLRs or non-IOU LSEs in a transition to a new POLR landscape.

In creating this Designated POLR Framework, the Commission should: (1) act to preserve the legislatively protected autonomy of non-IOU LSEs; (2) structure the Designated POLR Framework to focus on ensuring that any prospective Designated POLR fulfills the fundamental POLR obligation to serve returned customers; and (3) ensure the Designated POLR is able to recover all costs for its POLR service, through mechanisms similar to those established in prior POLR Decisions.[6] By focusing on these core POLR components, the Commission will faithfully implement the terms of SB 520, while harmonizing the Designated POLR Framework with California law limiting the Commission's regulatory jurisdiction over certain non-IOU LSEs.

As set forth in detail below, CalCCA provides the following overall recommendations in response to the "Threshold Questions" set forth in the Ruling:

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5 *See* D.24-04-009, *Decision Implementing Senate Bill 520 Regarding Standards for Provider of Last Resort,* R.21-03-011 (Apr. 18, 2024) (Phase 1 Decision).

6 For ease of reference and consistency with prior POLR comments and decisions, these comments use the phrase "returned customer" and "returned load" to refer to customers transferred from an LSE to a Designated POLR in the case of an involuntary transfer of load. However, in the case of a Designated POLR, those customers may not be "returning" to their former LSE as most customers would be in the case where an LSE fails today, and load is returned to the incumbent IOU POLRs.

- The Commission should move forward with establishing the framework for non-IOU LSE POLR service regardless of current interest among existing POLRs or non-IOU LSEs in transferring POLR service from an existing POLR to a non-IOU LSE POLR;

- The Commission's framework for non-IOU LSE POLR service should acknowledge that the Commission's regulatory authority over a non-IOU LSE POLR is limited to only the non-IOU LSE's POLR-specific services. Limiting the Commission's jurisdiction in this way will faithfully implement the text of California Public Utilities Code sections 216(a)(2) and 387(j), and will harmonize the oversight over a non-IOU LSE POLR with the Commission's existing, limited jurisdiction over non-IOUs;

- The Commission should provide a non-IOU POLR with the same forms of cost recovery now available to existing IOU POLRs unless and until there is a demonstration those existing forms of cost recovery will fail to make a non-IOU POLR whole for its role of serving returned customers. Such cost recovery should follow the same methodologies set forth in the POLR Phase 1 Decision, including requiring entities being served by the non-IOU POLR to post a FSR and pay re-entry fees; and

- To ensure the non-IOU POLR can fulfill its core POLR function while awaiting receipt of any owed re-entry fees, the Commission should require any non-IOU POLR to: (1) establish it has sufficient liquidity (45 days liquidity on hand) to provide energy service to the entire customer base of the largest LSE in its proposed POLR service area for one month's time; and (2) have an Investment Grade (IG) credit rating.

II. COMMENTS ON THRESHOLD QUESTIONS

1. Is there an IOU that is interested in transferring POLR responsibilities to a non-IOU LSE within its service territory?

It is reasonable for the Commission to gauge current interest among the existing POLRs in transferring POLR responsibilities to a non-IOU LSE, as that interest can inform the Commission's development of the Designated POLR Framework that section 387 requires. However, the Commission should not delay or postpone development of the Designated POLR Framework that can allow for a non-IOU LSE to become a POLR simply because existing POLRs may not be interested in transferring their POLR responsibilities today.

Section 387 explicitly provides the legislative mandate for the Commission to develop a Designated POLR Framework regardless of existing POLR interest. Section 387(d) states that "[t]he commission ***shall*** develop a process to facilitate a joint application from load-serving entities that are not electrical corporations to request to transfer the responsibilities of the provider of last resort."[7] Section 387(f) also directs that the Commission "***shall*** develop additional threshold attributes for a [LSE] other than an electrical corporation to serve as a provider of last resort to retail end-use customers in California[.]"[8] Sections 387(d) and (f), in other words, are the directives that catalyze this Phase 2. Neither directive is contingent on interest among existing POLRs in transferring their POLR responsibilities to another entity. California law is clear that the legislative choice to use the word "shall" signifies a mandatory legislative directive.[9]

Given these statutory mandates, answers to questions of whether there is interest in such a transfer should not impact the Commission's effort to chart a framework to fulfill the obligations of section 387. Instead, the Commission should focus on developing a framework to facilitate this transfer of POLR responsibilities to a Designated POLR and ensure the Designated POLR can serve customers during the period of POLR services.

a. If so, under what circumstances would the IOU be willing to transfer its POLR responsibilities to a non-IOU LSE?

CalCCA has no comment at this time, given this question is directed to the IOUs.

2. Is there a non-IOU LSE that is interested in becoming a non-IOU POLR within a specific territory?

CalCCA members may be potentially interested in exploring the option of becoming a Designated POLR, though that interest will be contingent on the outcomes of this proceeding.

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7 Cal. Pub. Util. Code § 387(d) (emphasis added).

8 *Id.* § 387(f) (emphasis added).

9 *Id.* § 14 ("'Shall' is mandatory and 'may' is permissive.").

Regardless, CalCCA and its members are interested in ensuring that the ability to take over POLR services is structured and maintained in a just and reasonable manner. The contingent nature of existing ***non-IOU*** interest in taking on POLR responsibilities should also not stop the Commission in developing that framework. Indeed, the language of section 387 is explicit: the Commission "***shall***" develop key portions of a framework for non-IOU POLR service, and those directives are not preconditioned on an expressed interest by an existing POLR in relinquishing POLR status, or by a non-IOU LSE in becoming a POLR.

a. If so, under what circumstances would the non-IOU LSE be willing to accept transfer of POLR responsibilities from an IOU POLR?

CalCCA members may be interested in accepting POLR responsibilities if the Commission's adopted Designated POLR Framework at least:

- Includes only limited Commission oversight over the non-IOU that becomes a POLR. Specifically, the Commission's jurisdiction should extend to the non-IOU's POLR-specific services only;
- Makes explicit that becoming a Designated POLR does not transform a non-IOU LSE into an electrical corporation as that term is defined, used, and regulated in the California Public Utilities Code and in the Commission's past decisions;
- Continues to recognize CCA governing-body authority over rate-setting for customers;
- Facilitates recovery by the Designated POLR of its POLR-related costs in the same manner as existing IOU POLRs as described in the Phase 1 Decision, or in a manner that ensures that the Designated POLR is "made whole," if it becomes clear that the current, IOU-specific methods of cost recovery are insufficient to make the Designated POLR whole;
- Analogous to the cost recovery mechanisms for IOU POLRs described in the Phase 1 Decision:
    - Provides that LSEs subject to a non-IOU POLR must post an adequate FSR, sufficient to cover the costs of re-entry fees adequate to compensate the

Designated POLR for the cost of serving the returned load, including any incremental procurement necessary to serve the returned load;[10]

- Provides that in the event of an involuntary transfer of load from an LSE to the Designated POLR, the re-entry fee must be paid by the originating LSE, and if the LSE cannot or does not pay the re-entry fee, the Designated POLR can draw on the FSR to cover the costs of the re-entry fees not paid by the LSE;[11] and
- Allows the Designated POLR to track and seek recovery of actual administrative costs (including any credit capacity or financing costs) and/or procurement costs associated with serving involuntarily returned load, consistent with the authority granted in the Phase 1 Decision to the existing, IOU POLRs.[12]

3. What is the scope of the Commission's authority over non-IOU POLR service providers under Pub. Util. Code Section 387?

Section 387(j) states:

> The commission shall supervise and regulate each provider of last resort***, as necessary,*** as a public utility ***for the services provided by the provider of last resort pursuant to this article to ensure the provision of electrical service to customers without disruption if a load-serving entity fails to provide, or denies, service to any retail end-use customer in California for any reason***. The commission may do all things that are necessary and convenient in the exercise of this power.[13]

Section 387(j) establishes that although the Commission is authorized to exercise a degree of regulatory supervision over a non-IOU LSE taking on POLR responsibilities, the Commission's authority is ***limited to that LSE's POLR-specific services***.

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10 *See* Phase 1 Decision, at 25-26 (describing the re-entry fees and FSR processes), and Conclusion of Law (COL) 9, at 105 ("The established cost recovery mechanisms for IOU POLR service are reasonable and satisfy the requirement in Section 387(g) to ensure the POLR receives reasonable cost recovery").

11 *See id.*, Finding of Fact (FOF) 64, at 101 ("In the event of a mass involuntary return of customers, CCAs have 15 days from an IOU's demand for payment to remit the calculated re-entry fees, after which the IOUs are authorized to immediately draw upon the defaulting CCA's FSR instrument in an amount not to exceed the re-entry fees").

12 *See id.*, COL 32, at 107 ("The POLR should be authorized, but not required, . . . to establish one or more memorandum accounts to track actual incremental administrative and/or procurement costs during a mass involuntary return of customers to POLR service").

13 Cal. Pub. Util. Code § 387(j) (emphasis added).

The Commission must give meaning to section 387(j)'s explicit statutory limitation when structuring the Designated POLR Framework. "It is a maxim of statutory interpretation that courts should give meaning to every word of a statute and should avoid constructions that would render any word or provision surplusage."[14] The legislature explicitly provided the Commission's ability to regulate POLRs "as necessary, as a public utility" ***only*** "for the services provided by the provider of last resort . . . to ensure the provision of electrical service to customers without disruption if a load-serving entity fails to provide . . . service[.]"[15] The concluding clause of that statutory language therefore explicitly limits the Commission's authority to regulate the Designated POLR to ***only*** the Designated POLR's ***POLR-specific services,*** which are the services the Designated POLR must provide to ensure service without disruption if an LSE fails to provide, or denies, service to retail end-use customers.[16]

It is important to note that had the legislature not intended the emphasized language to be a limitation on Commission authority, there would be no reason to include it at all in section 387(j). Instead, the legislature could have simply directed that once an entity becomes a Designated POLR, the Commission has authority to regulate that entity as a "public utility." That broader regulatory authority would necessarily include the ability to supervise the Designated POLR's POLR-specific services. So, to give meaning to ***all of section 387(j)***, as California law requires, the Commission must recognize that its ability to regulate a Designated POLR is ***limited***.

The other statutory provision affected by SB 520, section 216(a)(2), supports this conclusion:

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14 *Tuolumne Jobs & Small Bus. Alliance v. Superior Court*, 330 P.3d 912, 1038 (Cal. 2014).
15 Cal. Pub. Util. Code § 387(j).
16 *Ibid.*

> A provider of last resort, as defined in Section 387 . . . is a public utility subject to the jurisdiction, control, and regulation of the commission and the provisions of this part ***regarding providing that service***.[17]

Like section 387(j), this statutory provision is expressly limited by its concluding clause. Once again, the legislature determined that a Designated POLR is a "public utility" merely for the purpose of the Designated POLR's POLR-specific services, as the non-IOU LSE that becomes POLR is a "public utility" ***only*** "regarding providing that service."[18] This interpretation gives meaning to all of section 216(a)(2), as the Commission must.[19] This interpretation also harmonizes section 216(a)(2) with the Commission's expressly limited authority under section 387(j), as California law directs.[20]

Limited Commission authority is also consistent with existing Commission oversight—consistent with California law—over CCAs. CCAs are obligated to comply with certain procurement and reliability obligations (including the Commission's Resource Adequacy (RA), Integrated Resource Planning (IRP), and Renewable Portfolio Standards (RPS) programs), but the Commission is not authorized to scrutinize CCA rates, CCA procurement generally, or overall CCA financials. Relying on SB 520 to expand the Commission's authority would represent a significant and unwarranted alteration to current practices. The Commission should reject any such result.

Importantly, by recognizing that section 387(j) grants the Commission only limited jurisdiction over a Designated POLR, the Commission should not sanction a ratemaking regime without guardrails. CCAs are not subject to the Commission's rate, procurement, or financial

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[17] *Id.* § 216(a)(2) (emphasis added).
[18] *Id.*
[19] *Id.* § 387(j) (emphasis added).
[20] *See, e.g.*, *ZB, N.A*, *and Zions Bancorporation v. Superior Court,* 448 P.3d 239, at 248 (Cal. 2019); *Tuolumne Jobs*, 330 P.3d at 1038.

oversight in the manner of IOUs because they are directly responsive to their customers as public agencies. CCAs are also subject to numerous legal restrictions on public agency operations, including ratemaking.[21]

The public agency accountability and other provisions of State law ensuring that CCA charges remain in line with the reasonable costs of CCA service are analogous to the Commission's review of IOU rates and services and displaces the need for the same sort of regulatory supervision the Commission exercises over the IOUs. The need for extensive Commission jurisdiction is further reduced by the fact that POLR service is and should be rare and time limited. It only occurs in the case of returned load, and then only for a limited period of time before returned customers are either folded into the default provider's "normal" non-POLR service options, or returned customers depart POLR-service for a separate service option.

Section 387(j) contemplates a continuation of the existing approach to non-IOU LSEs. The legislature has authorized the Commission a degree of expanded regulatory authority over a Designated POLR, but the statute is explicit that this expanded authority should ***only*** encompass POLR-specific operations. The Commission must comply with that explicit legislative mandate when structuring the Designated POLR Framework.

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[21] As set forth in Public Utilities Code § 366.2, CCAs are formed for the purpose of aggregating the electrical load of interested customers in their service territory to procure electricity and energy services on those customers' behalf. Similar to municipal utilities, CCAs are public agencies. Their governing boards are comprised of local elected officials from the cities and counties that form the CCA. CCA governing boards exclusively set the rates for their electricity services. In addition, as public agencies, CCAs are subject to California open meeting, public record, and conflict of interest laws such as the Ralph M. Brown Act, the Public Record Act, and the Political Reform Act. CCA governing boards set electrical rates for their customers within a public process that already provides for decisions made in the public interest, with transparency, public participation, and public agency accountability.

a. How should the Commission apply existing public utility regulatory requirements (e.g., cost-of-service ratemaking, reporting requirements, etc.) to non-IOU POLRs? Does this authority change depend on whether the non-IOU POLR is a Direct Access (DA) Provider, a CCA, or another type of LSE?

SB 520 explicitly limits the Commission's regulation to include only the ***POLR-specific services*** of a non-IOU LSE that becomes POLR. Consequently, the framework for non-IOU POLR service should facilitate non-IOU POLRs recovering their costs of the POLR-specific services through rates to ensure such cost recovery. By separating the POLR-specific aspects of a Designated POLR's operations, the Commission will be able to exercise applicable regulatory authority over those POLR specific operations while ensuring the LSE's autonomy over the LSE's non-POLR operations. Critically, any Commission regulatory authority over the non-IOU POLR, including any potential rate review, should remain focused on the core POLR function of ensuring that the Designated POLR adequately serves returned customers. The Commission should not develop a Designated POLR Framework that acts as a backdoor to broader Commission control over non-jurisdictional LSEs like CCAs.

The core obligation of any POLR—whether an incumbent IOU POLR or a Designated POLR—is to "provide electrical service to any retail customer whose service is transferred to the" POLR or Designated POLR "because the customer's load-serving entity failed to provide, or denied, service to the customer or otherwise failed to meet its obligations[.]"[22] To fulfill that obligation, a Designated POLR will incur administrative costs associated with onboarding, serving, and off-boarding returned customers. The Designated POLR may also incur procurement costs. The Designated POLR must be able to apply for cost recovery for such POLR-specific services through the framework adopted in this proceeding. Commission jurisdiction or review of rates or cost

[22] Cal. Pub. Util. Code § 387(a)(3), (b).

recovery beyond the POLR-specific services is unnecessary to ensure that a Designated POLR fulfills its core POLR obligation and is thus foreclosed by the terms of section 387.

The extent to which the Commission can exercise authority over a non-IOU LSE that becomes the POLR necessarily depends on specific statutory language governing that LSE. However, the Commission retains discretion to approve of a transfer of POLR services to a prospective Designated POLR. The Commission should use that discretion to ensure that non-IOUs that become POLRs operate on an even playing field with respect to their Designated POLR service.

The limits on Commission jurisdiction between different types of LSEs is most apparent when considering the possibility that an ESP might apply to become a POLR. California Public Utilities Code section 394(f) states explicitly that nothing in the Public Utilities Act—which includes sections 216(a)(2) and 387(j)—"authorizes the commission to regulate the rates or terms and conditions of service offered by electric service providers."[23] This clear statutory limitation on Commission regulation of ESPs is in direct conflict with both sections 216(a)(2) and 387(j), even if those sections are construed to allow for Commission regulation of a Designated POLR's POLR-specific services only. That conflict could be read to bar the Commission from regulating even just the POLR-specific services of an ESP that seeks to become a POLR. But again, the Commission is not obligated to accept an application from an ESP to become a Designated POLR; instead, the Commission "***may*** designate a load-serving entity" to serve as a Designated POLR.[24] The terms of section 387 thus empower the Commission to apply the requirements of non-IOU POLR service fairly across the board, regardless of the precise nature of a prospective Designated POLR. As such, if the Commission concludes that it is authorized to regulate the POLR-specific

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23 *Id.* § 394(f).
24 *Id.* § 387(c).

services of a CCA that becomes a Designated POLR, it should also mandate that before another LSE can become a Designated POLR, the Commission must be permitted to regulate the POLR-specific services of that LSE either through California law or consent of the ESP to the Commission's POLR-specific jurisdiction. If the Commission determines that an ESP cannot consent to POLR-specific jurisdiction, under section 394(f), the Commission will be unable to approve an application from an ESP that wants to become a Designated POLR.

Ensuring that the Commission structures its regulation of Designated POLRs in a way that limits its authority to only the POLR-specific services the non-IOU LSE POLR provides is critical to ensuring the POLR regime complies with California law. It is similarly important that the Commission refrain from creating an uneven playing field among non-IOU LSEs. The Commission should use the discretion the legislature entrusted it with to avoid that result.

b. How should the Commission ensure against cost shifting among the regulated and non-regulated non-IOU services?

The Commission can protect against cost-shifting between POLR and non-POLR services by ensuring that the Designated POLR is financially able to serve returned customers. In addition, the Commission should review only the POLR-specific rates of a Designated POLR to ensure that those rates are not a cross-subsidy to non-POLR customers.

4. Does the Commission's regulation of the non-IOU LSE POLR as a public utility extend to non-POLR activities?

No. As explained above,[25] extending Commission regulation of a Designated POLR beyond the Designated POLR's, POLR-specific activities would violate the explicit terms of sections 387(j) and 216(a)(2). Also as noted above, the Commission must "give meaning to every word of a statute and should avoid constructions that would render any word or provision

[25] *See* Section II.3., *supra*.

surplusage."[26] Additionally, the Commission's limited jurisdiction over a non-IOU that becomes a Designated POLR makes sense for CCAs because they are accountable as public agencies and limited by other provisions of state law. IOUs are not subject to those same constraints, so full Commission jurisdiction in that case is necessary to protect ratepayers from exorbitant, monopoly, profit-motivated costs. The same is not true for CCAs.

The Commission's framework for non-IOU POLR service should recognize that the legislature explicitly delegated the Commission only limited authority to regulate a Designated POLR, and that limited authority extends only to the Designated POLR's POLR-specific services.

5. Is an IOU required to join in a Section 387(c) "joint application" when a non-IOU proposes to become a non-IOU POLR?

In section 387, the legislature made a choice to require the voluntary participation of both the existing IOU POLR and the non-IOU LSE in an application to transition POLR service from the existing IOU POLR to the prospective Designated POLR before the Commission can approve any such transfer. The maxim that the Commission must give meaning to all words in a statutory scheme and avoid interpretations that render words mere surplus once again dictates this conclusion.[27] Section 387(c) requires any application from a prospective Designated POLR be "joint" with the existing IOU POLR. A Designated POLR Framework that allows an LSE to force a reluctant, existing IOU POLR into nominally joining an application to transition POLR service—even if that existing POLR opposed the application—would not give appropriate meaning to that statutory language. Had the legislature envisioned such a scenario, the legislature could have explicitly required only an "application" from a prospective Designated POLR, rather than a "joint" one. Further, none of the statutorily mandated contents of the application clearly require

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[26] *Tuolumne Jobs*, 330 P.3d at 1038.
[27] *Ibid.*

input or information from the incumbent POLR. Therefore, the only possible reason the legislature could have had to require "joint" participation of the incumbent POLR and the prospective Designated POLR would be to ensure the voluntary participation of the incumbent POLR.[28]

In crafting the Designated POLR Framework; however, the Commission should acknowledge that this same logic must apply with equal force to non-IOU LSEs, either in the case where an incumbent, IOU POLR remains in place, or in the case where a non-IOU LSE has become a Designated POLR. In the first instance, the Commission should structure the Designated POLR Framework to affirmatively recognize that existing, incumbent POLRs cannot force a non-IOU LSE to initiate and join an application for the non-IOU LSE to become a Designated POLR, just as a prospective Designated POLR cannot force the incumbent IOU POLR to join such an application.

In the second instance, the framework for non-IOU POLR service must recognize that section 387(d) also requires a "joint application" to initiate the transfer of POLR service from one non-IOU LSE to another non-IOU LSE.[29] Again, the legislature made a statutory choice to require a joint application, which the Commission should read to require the voluntary participation of both parties. In the case of a transfer of POLR service between non-IOU LSEs, this means that both non-IOU LSEs—the existing Designated POLR and a separate, prospective Designated POLR—must be voluntary participants. The Commission should not adopt a framework where voluntary IOU participation is required for an application to move forward, but where a later non-IOU LSE interested in becoming POLR could ***force*** a non-IOU Designated POLR to join an application to oust that non-IOU Designated POLR.

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28 *See* Cal. Pub. Util. Code § 387(c).
29 *Id.* § 387(d).

The statutory text of section 387 preserves the autonomy and agency of existing, incumbent IOU POLRs, non-IOUs that are interested in becoming a Designated POLR, ***and*** non-IOUs that are not (and may never be) interested in becoming a Designated POLR. The statutory language requires the voluntary participation of both the existing POLR and any future replacement of that POLR and the Commission should preserve that statutorily protected autonomy in the development of the Designated POLR Framework.[30]

6. Regarding Section 387(f) Non-IOU LSE POLR "Minimum Threshold Attributes":

a. What are the Section 387(f) minimum financial requirements necessary for the non-IOU LSE POLR?

As noted above, the core obligation of any POLR—whether an incumbent IOU POLR or a future Designated POLR—is to "provide electrical service to any retail customer whose service is transferred to the" POLR or Designated POLR "because the customer's load-serving entity failed to provide, or denied, service to the customer or otherwise failed to meet its obligations[.]"[31] And section 387(f)(2) makes clear that the "[m]inimum financial requirements" the Commission should establish to govern Designated POLR service have the limited purpose of ensuring that the Designated POLR "provide[s] electricity to retail end-use customers," as necessary.[32] Nothing in the statutory text defining the contours of a Designated POLR Framework suggests that the financial requirements for a Designated POLR should be used as a broader tool to regulate a prospective Designated POLR beyond ensuring that it is capable of serving returned customers if and when necessary.

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30 *See id.* § 387(c), (d).
31 *Id.* § 387(a)(3), (b).
32 *Id.* § 387(f)(2).

The most direct way of ensuring that any Designated POLR stands ready to serve returned customers is to require Designated POLRs to: (1) maintain sufficient liquidity to serve the customer load of the single largest LSE within the Designated POLR's proposed POLR territory that it might be required to serve if that single LSE fails; and (2) maintain an IG credit rating. Specifically, and in addition to the IG credit rating, the Commission should require that the Designated POLR maintain 45 Days Liquidity on Hand (DLOH) to procure energy for one month (priced at the California Independent System Operator Corporation's (CAISO) average price over the last 12 months).[33] The calculation of energy for one month should be based on average monthly consumption over the last 12 months to serve the customer load of the single largest LSE within the prospective Designated POLR's proposed POLR territory if that LSE fails. This measure of liquidity will ensure that the Designated POLR stands ready to fulfill its fundamental service obligation even if it does not have immediate access to additional liquidity in the event of an involuntary return of load through a failing LSE's FSR or re-entry fee. As such, this liquidity metric, coupled with the additional requirement of an IG credit rating, fulfills the core obligations and goals of section 387.

b. Do these requirements align with the requirements of an IOU POLR?

No. Requiring Designated POLRs to maintain significant liquidity on hand to cover at least one month's worth of procurement to cover a sizable involuntary return of load is a more stringent requirement than the requirements for IOU POLR service. In fact, section 387 does not place ***any*** minimum criteria on IOU POLRs. Instead, section 387(b) simply establishes that IOU POLRs are the POLR by default, regardless of their financial health, liquidity, or credit worthiness.

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33 The DLOH to cover the energy purchases of the Designated POLR acknowledges the core requirements of the Designated POLR to ensure uninterrupted service through energy payments to the CAISO. Any RA or RPS requirements necessary to serve the returning customers can either be waived, or for RPS met during the three-year compliance period.

c. What are the threshold levels of "compliance with all state-mandated procurement requirements" for eligibility for a non-IOU LSE POLR per Section 387(f)(3)?

The Commission should require that a prospective Designated POLR has materially followed the Commission's program requirements for state-mandated procurement requirements for 12 months prior to the submission of the joint application. The Commission should explicitly clarify the Designated POLR Framework to make clear that a prospective Designated POLR that receives a waiver of a procurement obligation from the Commission or Commission staff is considered in compliance with state-mandated procurement obligations. In addition, overall compliance with Commission program requirements, such as the RA and IRP program requirements, and approval of a RPS plan, should also be considered in compliance with state-mandated procurement obligations. The Commission should retain discretion in its review of a joint application to determine whether a prospective POLR that has not met the state-mandated requirements for 12 months has been sufficiently compliant to serve as POLR.

7. Will a non-IOU POLR be entitled to cost recovery under the same conditions as the IOU POLR?

Section 387(g) mandates that the Commission "ensure that the provider of last resort for each service territory receives reasonable cost recovery for being designated and serving as a provider of last resort." This provision does not distinguish between the existing IOU POLRs and LSEs that become Designated POLRs in the future, signaling that the Commission should provide similar modes of cost recovery regardless of the precise nature of the POLR. As such, the Commission's Designated POLR Framework should assume that the methods of cost recovery appropriate for the existing IOU POLRs, as set forth in the Phase 1 Decision, are also suitable for future Designated POLRs.

However, the Designated POLR Framework should leave open the possibility that the current methods of cost recovery for existing IOU POLRs do not allow for full cost recovery if a non-IOU LSE becomes a Designated POLR. If that is the case, the framework should allow for the development of separate modes of cost recovery for the Designated POLR to ensure that the Designated POLR is made whole for its role as the POLR.

8. What technical, financial, and legal capacity thresholds should be required for non-IOU entities to serve as POLR?

As noted above, the core obligation of any POLR is to serve returned load returned because the customer's prior LSE failed to provide, or denied, service to that customer.[34] Section 387(f)(5) makes this point clear by allowing for the possibility of "additional minimum requirements" only as "needed to ensure that the provider of last resort will perform its obligation to serve." The Commission's framework for non-IOU POLR service should, accordingly, focus on ensuring that a prospective Designated POLR is able to fulfill that fundamental obligation.

As noted above, the Commission can fulfill the statutory goals by requiring that prospective Designated POLRs demonstrate 45 DLOH to procure energy for one month (priced at the CAISO average price over the last 12 months), based on average monthly consumption over the last 12 months for the largest single-LSE customer base within the Designated POLR's proposed territory. In addition, the Designated POLR can be required to have an IG credit rating.

The Commission should not require any further "technical, financial, and legal capacity thresholds" absent a finding by the Commission that the proposed threshold is necessary to ensure that Designated POLRs satisfy their core POLR function and serve returned customers.[35]

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[34] Cal. Pub. Util. Code § 387(a)(3).

[35] *See id.* § 387(f)(5).

9. Are there any additional threshold questions beyond those listed above that should be addressed before examining the two primary topic areas set out below?

No. However, CalCCA may supplement its response to this Threshold Question based on comments provided by other parties to this proceeding.

10. Are legal briefs necessary to determine whether SB 520 is sufficient to provide the Commission with authority to regulate the rates and terms and conditions of a non-IOU POLR, given the statutory provisions that limit the Commission's statutory authority to regulate ESP and CCA rates and terms and conditions of service?

Legal briefs are not necessary because the statutory text of section 387(g) unambiguously limits the Commission's authority to regulate a Designated non-IOU POLR to only that LSE's POLR-specific services. That limited expansion of Commission authority does not conflict with the limits on the Commission's statutory authority to regulate CCA rates and terms and conditions of service. And to the extent it does conflict with the limits on the Commission's authority to regulate the rates of ESPs, the Commission can avoid any such conflict by exercising its discretion to refrain from approving any ESP's service as POLR unless and until the ESP consents to Commission jurisdiction over the ESP's POLR-specific service, or the legislature revises the Commission's jurisdiction over ESPs.[36]

However, legal briefs will be necessary to the extent the Commission believes section 387 grants it jurisdiction over more than just the Designated POLR's POLR-specific services since, in that case, the Commission will benefit from a more thorough discussion on the unambiguous meaning of section 387(j).

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[36] *See* Section II.3.a., *supra*.

11. If the information provided in response to the threshold questions shows that there is no interest by a non-IOU LSE to become a POLR or for an IOU to transfer POLR responsibilities to a non-IOU LSE should the Commission address the primary area scoping issues set out below in this scoping memo?

Yes. As noted above, sections 387(d) and (f) both mandate that the Commission establish a framework for non-IOU POLR service.[37] Neither provision is contingent on current interest from an existing IOU POLR in relinquishing POLR responsibilities or a non-IOU LSE in taking on POLR responsibilities. Further, IOU or non-IOU interest in relinquishing or taking on POLR responsibilities may change as this proceeding develops. If the Commission halts this proceeding now (assuming there is no current interest) the Commission will not just ignore the statutory directives of section 387 but may well find that it stunted any potential interest in non-IOU POLR service. The Commission should avoid the temptation to kick the can down the road and should instead continue forward with this Phase 2 proceeding regardless of current interest among LSEs in transitioning POLR service to a non-IOU LSE.

III. CONCLUSION

The legislature through Senate Bill 520 granted the Commission important but limited authority to conceptualize and then regulate the possible operations of a Designated POLR. The Commission's framework for non-IOU POLR service should: (1) acknowledge this limited authority; (2) focus only on ensuring that any prospective Designated POLR fulfills its fundamental POLR obligation to serve returned customers; (3) ensure the non-IOU POLR receives adequate cost recovery for that obligation; and (4) respect the legislatively protected autonomy of non-IOU LSEs.

[37] Cal. Pub. Util Code § 387(d), (f); *see also id.* § 14 ("'Shall' is mandatory and 'may' is permissive.").

CalCCA respectfully requests that the Commission adopt a framework consistent with the above comments.

Respectfully submitted,
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January 10, 2025

On behalf of the California Community Choice Association

DOCKETED	
Docket Number:	23-DECARB-01
Project Title:	Inflation Reduction Act Residential Energy Rebate Programs
TN #:	261041
Document Title:	Joint Community Choice Aggregators (Joint CCAs) Comments - Joint CCA Comments on the RFI for Program Design of IRA HEERHA Phase II
Description:	N/A
Filer:	System
Organization:	Joint Community Choice Aggregators (Joint CCAs)
Submitter Role:	Public
Submission Date:	1/10/2025 2:23:23 PM
Docketed Date:	1/10/2025

Comment Received From: Joint Community Choice Aggregators (Joint CCAs)
Submitted On: 1/10/2025
Docket Number: 23-DECARB-01

Joint CCA Comments on the RFI for Program Design of IRA HEERHA Phase II

Additional submitted attachment is included below.

January 10, 2025

California Energy Commission
Docket Unit, MS-4
Docket No. 23-DECARB-01
715 P Street,
Sacramento, CA 95814

RE: Joint CCA Comments on the Request for Information, Program Design of Inflation Reduction Act Home Equipment and Appliance Rebates Phase II

Dear Executive Director Drew Bohan and Commission Staff,

Sonoma Clean Power Authority ("SCPA"), Silicon Valley Clean Energy ("SVCE"), Peninsula Clean Energy ("PCE"), and Marin Clean Energy ("MCE"), are pleased to provide coordinated responses to the California Energy Commission's ("CEC") Request for Information ("RFI") on the Program Design of Inflation Reduction Act ("IRA") Home Equipment and Appliance Rebates ("HEEHRA") Phase II.

The load serving entities listed above represent a coalition of community choice aggregators ("Joint CCAs") providing electric service to more than 1.4 million customer accounts within Pacific Gas and Electric Company's ("PG&E") service area. The Joint CCAs offer a number of energy efficiency, demand response and decarbonization programs aligned with HEEHRA Phase II goals and bring that program design, implementation and evaluation experience to these comments.

The Joint CCAs would like to thank the CEC for the opportunity to provide responses to the HEERHA Phase II RFI. The Joint CCAs support the CECs mission to successfully implement the State's progressive decarbonization and electrification goals and we welcome the opportunity to provide input on the design on Phase II of the HEERHA program. The $152 million allocated to Phase II offers the potential to save money for customers served by the Joint CCAs and other load serving entities throughout the state. The successful design and implementation of HEERHA comes at a critical time for ratepayers in California facing rising energy bills. The comments in the Appendix provide insight into the unique perspective offered by CCAs throughout diverse regions of California.

Thank you for your time and consideration. Please do not hesitate to reach out to any of the undersigned parties below with any questions or if you wish to further discuss these responses.

Sincerely,

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Appendix –
Responses to Requested Feedback:

The Joint CCAs respectfully offer feedback on the following questions to help inform the development of the HEERHA Phase II program:

1. ***Eligible Equipment and Appliance Rebates***

   Should all DOE eligible equipment (listed in Table 1) be available to single-family households and multifamily properties?

The Joint CCAs believe that all DOE-eligible equipment listed in Table 1 should be available to both single-family households and multifamily properties. Providing access to the full range of eligible equipment ensures equity and inclusivity in how rebates are distributed, allowing households and property owners to select solutions that best address their unique needs and circumstances. Single-family households and multifamily properties often face different challenges and opportunities when pursuing energy efficiency upgrades or electrification projects; a technology-inclusive program design will enable a larger number of customers to benefit from incentives that they may have missed or otherwise not been ready to pursue in Phase I. Funding for heat pump HVAC systems was available for single-family homes in Phase I of HEEHRA, but did not include incentives for electrical panel upgrades. This next phase of funding will be essential to address significant gaps that exist for homes requiring panel upgrades and wiring actions in order to safely install heat pump HVAC units.

In addition, the CEC should allow prewiring as an eligible cost for the electrical wiring incentive. This encourages homeowners to plan for future electrification needs. For homes that are not yet ready to fully electrify all end uses, prewiring can minimize future costs and disruptions by enabling efficient placement of circuits and outlets. Since 2024, SVCE's $500 pre-wiring rebate has encouraged the installation of 471 pre-wired circuits for future electric end-uses such as water heating, space heating, electric vehicle ("EV") charging, electric induction cooking, and electric drying.[1] Providing access to all technologies in Phase II is critical to expanding the scope of work and ensuring households of all types can fully benefit from these incentives.

   a. ***Should the rebate amounts be reduced to allow more households to receive a rebate? If yes, please provide recommended amounts and rationale.***

The Joint CCAs recommend the CEC retains rebate amounts in full, and that incentives should not be reduced. The proposed rebate levels are essential for ensuring low- and moderate-income households can afford to participate, even though they do not cover the full cost of most projects. In addition, there are tremendous regional differences in access to contractors, technologies, labor costs, and cost of living. In regions with high living and labor costs, project expenses often far exceed these rebates, and many zero-emission technologies have not yet reached price parity with combustion appliances.

[1] Silicon Valley Clean Energy's Home Rebates Program: *https://svcleanenergy.org/home-rebates/*

In addition, California's high electricity prices (particularly increasing IOU distribution and wildfire costs)[2] greatly reduce potential for customers to lower their utility bills through whole-home electrification, despite reducing home energy consumption by nearly 60%. As a result, the Joint CCAs believe the true retrofit costs require the full rebate to properly incentivize fuel-switching, and that such costs present a significant burden on low-income, disadvantaged, and otherwise under-resourced households if not mitigated at the adoption phase.

Maintaining the current rebate amounts is particularly critical for supporting participation in these areas. Additionally, we recommend collaboration with other rebate providers to allow for streamlined and low administrative burden program stacking processes. Leveraging additional funding will help to reach more households and will be necessary to further enhance affordability and accessibility, especially for low-income households and other environmental and social justice communities facing barriers to decarbonization.

2. Regional Allocation and Customer Engagement

a. To ensure fair geographic disbursement of funding and align with other energy equity programs, CEC allocated HEEHRA Phase I funding to three regions of California based on the proportion of under-resourced communities. This formula provides 23 percent of funding to Northern California, 19 percent to Central California, and 58 percent to Southern California. CEC is considering a similar allocation approach for HEEHRA Phase II funding. Should CEC consider other factors to ensure statewide distribution?

Yes, Joint CCAs strongly support a regional approach to HEEHRA Phase II implementation based on the proportion of under-resourced communities. Joint CCAs believe decarbonization programs are best implemented at the local or smaller regional levels. Local and regional approaches allow programs to better respond to the diversity of local needs.

Joint CCAs also support prioritizing under-resourced communities given the many barriers to decarbonization and access to rebate programs that they face while simultaneously experiencing disproportionate health burdens of energy pollution.[3]

b. Are there other active or past rebate programs in California or the United States with high uptake in underserved communities that CEC can learn from?

Within the Joint CCAs, MCE specifically administers low or no cost direct-install energy efficiency programs with a decarbonization and equity focus, like its Home Energy Savings program, Multifamily Energy Savings program and formerly offered the Low-

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[2] 2024 Senate Bill 695 Report, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2024/2024-sb-695-report.pdf, pp. 1-3.

[3] Environmental Protection Agency, Cumulative Impacts Research, September 2022, available at: https://www.epa.gov/system/files/documents/2023-05/CUMULATIVE%20IMPACTS%20RESEARCH-FINAL%20REPORT-EPA%20600-R-22-014A%20%2812%29.PDF (outlining and defining the cumulative impacts of built and social environments on human health).

Income Families and Tenants program. PCE administers a direct install program that has served over 300 households in 3 years with no cost electrification upgrades. This program will be scaled up in 2025 to serve more households with whole-home electrification projects.

MCE and PCE wish to emphasize one key lesson learned from administering these programs:

It is essential for program success to serve low to moderate income households to cover the total project cost of measures, including technology and readiness measures like mold and pest remediation and electrical remediation that must occur prior to an eligible rebate installation.

Additionally, on the ground outreach methods such as canvassing by local community-based organizations has helped to enroll hard-to-reach customers that may not be as easily reached through online and email marketing tactics. In Spring 2024, SVCE launched its no-cost direct-install program for deed-restricted multifamily properties. In Fall 2024, SVCE launched their no-cost direct-install program for low-income single-family customers. As agencies with connections in our local community and networks of community-based organizations, the Joint CCAs are well-positioned to test different program implementation and engagement strategies that best fit our communities' diverse needs.

The Joint CCAs hope to demonstrate the success of direct install and other programs and identify challenges and potential solutions for future scalability. We would collectively like to support the CEC team in whatever way is helpful as HEEHRA is rolled out. We will be happy to share with information surrounding our program learnings, best practices, and challenges confronted with the launch of our electrification direct install programs with CEC staff at any time.

3. Contractor Engagement and Support

a. What are effective methods to recruit contractors to participate in the program, especially in underserved, disadvantaged, low-income, and rural communities?

The Joint CCAs have worked to develop thoughtful and robust workforce and contractor network development actions over the years. The Joint CCAs have identified the following best practices to be effective methods for contractor recruitment, particularly in disadvantages and underserved communities:

Build trust and relationships:

Building trust is essential for contractor recruitment, especially in underserved communities. Engaging local organizations such as trade schools and community-based organizations can help to identify trusted contractors, while hosting community events like meet-and-greet sessions and networking opportunities can foster rapport while sharing program information. Using culturally relevant materials and communication channels preferred by the community, such as local radio, websites, newsletters and social media, is critical in making program details widespread. Additionally, direct outreach to installers ensures targeted and effective engagement.

Offer incentives:

Offering incentives is another method for recruitment. Providing subsidized or free training, paying lost wages for attendees of trainings, certifications, or licensing fees can reduce barriers to entry for contractors. Bonuses or higher reimbursement rates for contractors who serve disadvantaged communities can further encourage participation. For example, SVCE's free contractor training program provides a $500 training incentive for those who complete the online electrification course. After completing the training, contractors can receive a subsequent bonus incentive, up to $5,000 a year, for installing electrification appliances for SVCE customers. Establishing a minimum number of projects installers can take on, guarantees consistent opportunities for smaller contractors and promotes equitable funding distribution.

Tailored training and support:

Tailored training and support are critical to fostering program participation. Offering multilingual, culturally competent, and up-to-date training, pairing experienced installers with newer entrants, and providing ongoing technical and administrative assistance can help contractors navigate program compliance. Hosting HEEHRA events that connect installers with suppliers, customers, and industry stakeholders not only strengthens their professional networks but also helps provide confidence in the program. The Joint CCAs support the CEC in efforts to pay for, or supplement, the lost wages of contractors and employees attending trainings. Specifically, MCE uses this approach in its Green Workforce Pathways program and has found it to be a valuable means of supporting education and fostering interest in training opportunities.

Simplify participation:

A major barrier to contractor participation in past programs has been the administrative burden and complexity of program participation. Streamlining processes to reduce paperwork, allowing for flexible scheduling to accommodate installer timelines, as well as clearly communicated program benefits can help foster transparency and increase contractor interest. The CEC should seek to minimize the complexity absorbed by contractors and rebate administrators wherever possible.

Career opportunities:

Promoting the program through vocational schools and apprenticeships programs and fostering trust in the new generation of installers by providing aid to workforce development programs. Sharing success stories from similar communities and emphasizing how program participation can grow an installers' client base over time showcases the programs long-term value.

Other:

The CEC may also wish to explore the CPUC's GO 156 Supplier Diversity Clearinghouse of certified diverse businesses for relevant outreach opportunities.[4]

b. ***What type of training should the CEC offer to help installation contractors understand program requirements and streamline rebate processing for retailers, contractors, and homeowners?***

To help contractors effectively understand program requirements and streamline rebate processing, the California Energy Commission should offer comprehensive and accessible trainings tailored to installation contractors. The Joint CCAs believe the following elements are key to effective training:

Program compliance and requirements:

Trainings should cover HEEHRA program rules, eligibility requirements, and necessary documentation. This includes step-by-step guidance on navigating the application and approval process, including highlighting how to avoid common errors. Tutorials on how to use digital platforms for rebate submission and tracking, as well as streamlined tools for managing customer information, project details and paperwork, should be provided to enhance program efficiency.

Technical training:

Hands-on workshops and virtual demonstrations should focus on the installation and maintenance of eligible measures. These sessions should include updates on new technologies, industry best practices and energy efficiency standards to help contractors stay informed.

Customer engagement and communication:

Installers should receive guidance on effectively conveying program benefits and requirements to customers. Trainings should include strategies for addressing customer concerns regarding cost, timelines, and expected outcomes, which in turn fosters transparency and trust.

Certification and continuing education:

Offering certification upon training completion can help to build credibility and customer trust. Ongoing educational programs should keep installers updated on evolving program details, energy efficiency trends and other available incentives and rebates, guaranteeing they remain competitive and knowledgeable in the industry.

Quality control:

Training should incorporate quality control measures and clear requirements.

Manufacturer and existing network collaboration:

[4] GO 156 Supplier Diversity Clearinghouse, available at: https://thesupplierclearinghouse.com/the-supplier-clearinghouse/.

Trainings should include partnerships with manufacturers of the specific technologies. In addition, contractors should be connected to additional training opportunities, such as decarbonization-focused resource like the Switch is On.

Multilingual and inclusive trainings:

To reach underserved communities, trainings should be offered in multiple languages with culturally relevant examples and scenarios. Additionally, mentorship programs pairing experienced contractors with new installers can help build capacity and confidence among less experienced contractors.

4) *Point-of-Sale Methodologies*

a. How can CEC facilitate homeowners obtaining a rebate when shopping online? Are there any program design considerations or best practices unique to an online sales point?

The Joint CCAs believe there are multiple viable means of issuing online rebates. Specifically, SCPA launched an electric bike point-of-sale incentive, where the rebate was applied directly as a discount at the bike store. Customers applied online for a voucher, which was mailed to them once approved. PCE has also offered point of sale rebates of both e-bikes and electric vehicles at local bike shops and dealerships. A portal was created for these retails to submit these reimbursement requests for the customers receiving rebates.

Ideally, a point-of-sale process has an easy and quick method for customers to verify their eligibility and receive their voucher, and customers do not need to be involved in the back-end reimbursement process for the retailer. The California Golden State Rebate Program is another example of a successful point of process where customers apply for coupon voucher by simply entering their electric account information and receive an email voucher usable at participating retailers.

b. How can CEC support small and local business owner participation in the program design?

The CEC can support small and local business owner participation in program design through intentional personal contact and proactive outreach. For example, during the development of SCPA's Electric Bike Incentive program, agency staff personally visited every store that enrolled to discuss the program face-to-face. This approach not only built trust but also allowed staff to understand the unique needs and perspectives of each business owner.

c. What are options for homeowners who don't have a smartphone and want to receive a rebate in store?

For SCPA's Electric Bike Incentive program, individual vouchers were provided by mail. While this approach was somewhat costly, it served as an effective measure to ensure that the program remained accessible to everyone, regardless of their access to digital technology. Mailing physical vouchers allowed participants to redeem their rebates in-store without relying on a smartphone or internet access, making the process more equitable and inclusive.

d. What are challenging elements with existing point-of-sale rebate programs and what are some solutions or best practices to minimize or eliminate the challenge?

There are several significant challenges with existing point-of-sale rebate programs, each of which can create barriers for both customers and contractors. One major issue is the burden of income verification, which can exclude qualified, historically underserved customers. Requiring extensive documentation for income verification often creates inequitable barriers, particularly for those who are most in need of assistance.

The Joint CCAs recommend the CEC limit any burdensome income verification processes which have been demonstrated to exclude qualified, historically underserved customers. Simple and direct strategies – such as self-attestation – for income qualified rebates to prevent inequitable barriers to access for intended recipients and fosters participation across customer classes. For example, MCE successfully uses self-attestation for income verification in its low-to-moderate income focused Home Energy Savings program. Joint CCAs observe other low-income serving energy programs like California Alternate Rates for Energy (“CARE”) and Family Electric Rate Assistance programs use self-attestation to establish income eligibility.

Another challenge with existing point-of-sale rebate programs involves delayed rebate payments to installation contractors. In many cases, contractors float the rebate amount upfront, relying on timely reimbursement from the rebate program. When payments are delayed, contractors can face cash flow issues, limiting their ability to take on additional projects. This is particularly concerning as the market looks to scale up the adoption of electrification technologies through programs like HEEHRA.

The Joint CCAs recommend designing the program to expedite payments to alleviate cash flow challenges. Faster payments will lead to more effective operations, enabling a higher volume of projects and support broader adoption of electrification measures.

Finally, some existing point-of-sale rebate programs involve significant paperwork and require customers to navigate complex eligibility criteria, often leading to confusion, eroded trust, and disengagement. This complexity can create barriers to participation, particularly low to moderate income households, environmental and social justice communities and others historically underserved by existing programs. To improve accessibility, the Joint CCAs recommend simplifying the process by minimizing paperwork, documentation collected from customers to determine eligibility and reducing the background knowledge required from customers. Streamlining the application and eligibility processes would make it easier for more people to participate without feeling overwhelmed by administrative hurdles.

In summary, addressing these challenges requires a multifaceted and flexible approach. Reducing income verification burdens, expediting contractor rebate payments, and simplifying customer application processes are all essential to creating a more equitable and efficient point-of-sale rebate system that can scale effectively.

5. Do-it-Yourself (DIY) Considerations

a. What are best practices to ensure a quality DIY install? What type of proof should be provided?

Best practices to verify a DIY installation should include:

Photo or video evidence:
Installers should submit a video or photo documenting the installation.

Permits:
For measures that require permitting, proof of permitting should be submitted.

Receipts & Invoices:
Detailed receipts for materials and project-related costs should be provided.

b. What are some guidelines and best practices for a program that allows for DIY installation of eligible equipment?

Some guidelines and best practices for programs supporting do it yourself (DIY) installations of eligible equipment include but are not limited to the following:

Clear eligibility criteria:

To ensure success in a DIY installation, clear eligibility criteria should be established. This includes outlining eligible equipment and specifying any restrictions such as measures that requiring permitting or professional installation. HEEHRA Phase II should also provide clear guidelines on who qualifies for a DIY install, ensuring participants have access to resources that enable safe and effective work.

Quality assurance:

To maintain quality assurance, participants should be required to submit documentation, such as photos or videos to verify that the installation was completed correctly. Additionally, the language should make it clear that DIY installations must meet all program and local code requirements.

Right to inspect:

Reserving the right to inspect completed work and installed measures adds an additional layer of quality assurance. Another best practice involves randomly selecting 5-10% awards to DIY projects for quality assurance inspections. This flexibility offers opportunities to ensure satisfactory use of incentives in the event that additional monitoring is deemed necessary. In doing so, it is essential that any customer accepting an incentive for a DIY install is made aware of any such audit protocols prior to accepting an incentive.

Completion checklist:

A completion checklist that outlines each step in the process to complete a successful project is helpful for a DIY customer. The steps could include confirming that the chosen appliance meets the performance requirements, applying for a project permit (if required), purchasing the appliance, installing the appliance, completing a final inspection for the permit (if required), and applying for the rebate with the necessary documentation. This clearly communicates the programs expectations to DIY participants.

Self-attestation:

A self-attestation that the installation meets program guidelines should be included.

Simplicity:

Streamline the application to make participation straightforward and user-friendly.

c. Are there other successful rebate programs in California or the United States that have provided rebates for DIY installed eligible equipment?

SCPA, SVCE and PCE offer rebates for the self-installation of heating, ventilation and air conditioning heat pumps, heat pump water heaters and induction cooking solutions. The inclusion of DIY installations in SCPA, SVCE and PCE's rebate programs is designed to improve access to incentives while promoting efficient electric technologies. While SCPA's program is not limited to DIY projects, it offers a valuable opportunity for technically skilled participants to reduce costs associated with expensive installations.

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

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resource Future.	R.21-06-017

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS REGARDING FUTURE GRID STUDY REPORT

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January 10, 2025

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SUMMARY OF RECOMMENDATIONS

CalCCA recommends that the Commission:

- Adopt the Joint IOUs'[1] position that the grid orchestration and open access frameworks are both necessary to support a high DER future;

- Reject the Joint IOUs' recommendation to not consider a statewide DER registry, data hub, or marketplace in the near term;

- Adopt the Joint IOUs' recommendation to prioritize DER visibility to the CAISO, but reject the suggestion that stakeholder workshops are unnecessary; and

- Reject SDG&E's recommendation to modify the FGS Report to state that flexible load energization is a temporary solution and to not develop a roadmap for flexible load energization.

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

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

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resource Future.	R.21-06-017

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS REGARDING FUTURE GRID STUDY REPORT

California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to the *Administrative Law Judge's Ruling Seeking Comments Regarding Future Grid Study Report*[3] (Ruling), dated October 17, 2024. The Ruling seeks comments on the Future Grid Study Report (FGS Report), including responses to specific questions posed in the Ruling.

I. INTRODUCTION

In response to party Opening Comments,[4] CalCCA recommends that the Commission:

- Adopt Pacific Gas and Electric Company (PG&E's) and Southern California Edison Company's (SCE's) (together, the Joint IOUs') position that the grid orchestration and open access frameworks are both necessary to support a high distributed energy resource (DER) future;

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

[3] *Administrative Law Judge's Ruling Seeking Comments Regarding Future Grid Study Report*, Rulemaking (R.) 21-06-017 (Oct. 17, 2024): https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=543421872.

[4] All references herein to party Opening Comments are to the opening comments filed in this proceeding, R.21-06-017, on or about December 16, 2024.

- Reject the Joint IOUs' recommendation to not consider a statewide DER registry, data hub, or marketplace in the near term;
- Adopt the Joint IOUs' recommendation to prioritize DER visibility to the California Independent System Operator Corporation (CAISO), but reject the suggestion that stakeholder workshops are unnecessary; and
- Reject San Diego Gas and Electric Company's (SDG&E's) recommendation to modify the FGS Report to state that flexible load energization is a temporary solution, and to not develop a roadmap for flexible load energization.

II. THE COMMISSION SHOULD ADOPT THE JOINT IOUS' POSITION THAT BOTH THE GRID ORCHESTRATION AND OPEN ACCESS FRAMEWORKS ARE NECESSARY TO SUPPORT A HIGH DER FUTURE

The Commission should adopt the Joint IOUs' position that both the top-down grid orchestration and bottom-up open access frameworks are necessary to support a high DER future.[5] The Joint IOUs state that the FGS Report incorrectly presents these frameworks as diverging visions when, in fact, they are complementary and should be pursued in tandem.[6] To pursue both frameworks will optimize the greatest number of DERs to support the reliable, efficient, and cost-effective operation of a high DER grid. Both frameworks must be developed to work in concert given: (1) the large number of DERs managed by non-investor-owned utility (IOU) load serving entities (LSEs), and third parties; (2) the expected load growth from building and transportation electrification; and (3) the lengthy IOU energization delays.

The Joint IOUs' Opening Comments state the need to pursue both the grid orchestration and open access frameworks:

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5 *See* Joint IOUs Opening Comments, at 2 and 9: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M548/K361/548361566.PDF.

6 *Ibid*.

> "DER orchestration" [*sic*] and "open access", [*sic*] key concepts raised in the Ruling, are not two competing or conflicting approaches, but rather two components of the same integrated vision. The Joint IOUs need both DER orchestration – i.e., centralized analysis of grid needs and signaling of these needs to DERs – as well as open access – i.e., making it straightforward for DERs (as well as customers and aggregators) to understand participation options, requirements, and potential compensation.[7]

The Joint IOUs further clarify that "[w]hen the Joint IOUs refer to DER orchestration, that does not mean the DSO [distribution system operator] controls every DER at all times."[8] The IOUs will not have visibility or control of DERs not directly enrolled in an IOU program, pilot, or tariff. Grid orchestration must be combined with an open access grid to fully leverage non-IOU DERs to benefit the grid.

During FGS Workshop #1, the Joint Community Choice Aggregators[9] (Joint CCAs) presented several examples of DER programs they have already deployed, many of which are optimized around wholesale market conditions rather than distribution grid support.[10] The Joint CCAs stated they "lack sufficient information and incentive to optimize programs based on distribution needs."[11] An open access framework will enable CCA-managed DERs to provide beneficial grid services in response to signals and compensation from the IOUs.

One example of a hybrid grid orchestration/open access approach involves direct communication between an IOU DER Management System (DERMS) and a non-IOU LSE

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7 *Id.*, at 2.

8 *Id.*, at 10.

9 The Joint CCAs, all members of CalCCA, include Ava Community Energy (formerly East Bay Community Energy), Peninsula Clean Energy, San Diego Community Power, San Jose Clean Energy, Silicon Valley Clean Energy, and Sonoma Clean Power.

10 *See* Joint CCAs' California FGS Workshop #1 Presentation, *Enabling DER Programs that Provide Distribution System Value: CCA Perspective*, R.21-06-017 (Feb. 8, 2024) (Joint CCAs' Presentation): https://gridworks.org/wp-content/uploads/2024/02/Joint-CCA-Deck-for-Future-Grid-Workshop-1-2.8.24-R.21-06-017.pdf.

11 *Id.*, slide 5.

DERMS, with a contract between the parties to compensate for verified performance. Another example is a distribution marketplace, where IOUs provide data on grid needs and values to the market operator, which schedules and signals DERs in response to this information and manages settlements between IOU and DER providers. Under either example, IOUs will orchestrate DERs enrolled in their own programs in harmony with non-IOU managed DERs participating under an open-access grid framework. The Commission should, therefore, adopt the Joint IOUs' position that both the grid orchestration and open access frameworks are necessary.

III. THE COMMISSION SHOULD REJECT THE JOINT IOUS' RECOMMENDATION TO NOT CONSIDER A STATEWIDE DER REGISTRY, DATA HUB, OR MARKETPLACE AT THIS TIME

The Joint IOUs' recommendation to not consider the development of a statewide DER registry, data portal, or marketplace "at this time"[12] is shortsighted and should be rejected. The Joint IOUs contend that a statewide DER registry and data hub will duplicate IOUs' development of Advanced Distribution Management System (ADMS) /DERMS technologies and existing IOU portals.[13] The Joint IOUs also describe several challenges in developing a marketplace and suggest focusing on local grid services instead.[14] Rather than delaying consideration of these measures as the Joint IOUs recommend, the Commission should immediately begin exploring ways to animate a distribution marketplace and provide access to the data necessary to support market operations.

Open access to the distribution grid should be a high-priority operational need to ensure DERs enrolled in both IOU and non-IOU programs operate harmoniously to support the distribution grid. Non-IOU LSEs and other DER owners/operators must have access to data on

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12 Joint IOUs Opening Comments, at 14.
13 *Ibid.*
14 *Id.*, at 15.

grid conditions, customer loads, DER locations, and DER operational characteristics for an open-access grid to function. Access to this type of data is foundational to developing a statewide marketplace.

In addition, the potential challenges of developing a marketplace cited by the Joint IOUs[15] have not hindered the development of marketplaces elsewhere, such as the National Grid example presented by Utility Consumers' Action Network (UCAN) at FGS Workshop #1.[16] Moreover, developing a distribution marketplace can alleviate the IOUs' concerns about providing access to real-time data via their ADMS/DERMS. A marketplace can securely handle large volumes of transactions between DER providers and IOUs, eliminating the need to provide multiple entities with ADMS/DERMS data access.

The Joint IOUs' explanation of why they believe a DER registry is duplicative fails to recognize that non-IOU LSEs, the CAISO, and other third-party DER owners/operators need access to much of the DER information the IOUs possess. The Joint IOUs also fail to explain how they intend to provide access to this data in lieu of considering a DER registry, data hub, or marketplace. While the Joint IOUs acknowledge the potential need for a data hub to support a statewide marketplace, they discourage consideration of a statewide data portal.[17]

Markets are complex, require careful design, and represent long-term solutions. Because of this complexity, the Commission should not delay considering the rules, structure, protections, and data needed to support the development of a marketplace. Such a delay would not hinder the IOUs' efforts to independently enable circuit-level grid services, including from non-IOU LSE

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15 *Ibid*.

16 UCAN Workshop Presentation, *R.21-06-017, Track 2: Future Grid Workshop #1, Operational Needs for California's High DER Future*, R.21-06-017 (Feb. 8, 2024), slides 11-12: https://gridworks.org/wp-content/uploads/2024/02/UCAN_Future-Grid-Workshop-1-Feb.-8-2024-public-final.pdf.

17 Joint IOUs Opening Comments, at 14.

and third-party DERs. It may also provide valuable insights for optimizing DERs via a future distribution marketplace.

Since the IOUs are already collecting DER data to support the launch of their ADMS/DERMS technologies, they should immediately begin working on third-party access to DER data, such as via a platform modeled after California Distributed Generation Statistics (DG Stats). The IOUs should also consider data exchange protocols and requirements to support a distribution marketplace in their ongoing development of ADMS/DERMS technologies. As such, the Joint IOUs' recommendation in Opening Comments to not consider the development of a statewide DER registry, data portal, or marketplace at this time is shortsighted and should be rejected.

IV. THE COMMISSION SHOULD ADOPT THE JOINT IOUS' RECOMMENDATION TO PRIORITIZE DER VISIBILITY TO THE CAISO, BUT REJECT THEIR SUGGESTION THAT STAKEHOLDER WORKSHOPS ARE UNNECESSARY

The Commission should adopt the Joint IOUs' recommendation to include DER visibility to the CAISO as a high-priority operational need, but reject the suggestion that stakeholder workshops are unnecessary. DER visibility to the CAISO should be a high priority for unlocking the full economic potential of CCA-managed DERs, and work should begin as soon as practicable to lay the groundwork for accomplishing this objective. Much of this foundational work centers around determining the CAISO's data needs and the IOUs' ability to provide the necessary data. Opening Comments of the Joint IOUs, SDG&E, and CAISO acknowledge the need to work directly with one another to determine the CAISO's data needs as an initial step before engaging with stakeholders.[18] While these discussions should initially occur between the

[18] *See* Joint IOUs Opening Comments, at 34; SDG&E Opening Comments, at 22: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M548/K361/548361567.PDF; and CAISO Opening Comments, at 1-6: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M548/K970/548970071.PDF.

CAISO and IOUs, the Joint IOUs' statement that "the issue is not particularly germane to most stakeholders,"[19] and their suggestion that stakeholder workshops are unnecessary, are misguided and should be rejected for the reasons discussed below.

The CAISO cites their concern over the impacts of the rapid growth of behind-the-meter (BTM) DERs as the reason for greater visibility of DERs.[20] CCAs already offer many DER programs and plan to ramp up DER enrollment, as the Joint CCAs detailed in their presentation during FGS Workshop #1.[21] The capacity these DERs provide may be used to meet an LSE's Resource Adequacy (RA) procurement obligation. Given the increased costs and difficulty procuring RA, enabling greater DER visibility to the CAISO may be necessary for these BTM resources to participate in the wholesale market and be counted towards an LSE's RA obligation. Contrary to the Joint IOUs' assessment, the issue of DER visibility at the transmission and distribution interface is of great importance to CCAs.

Discussions between the CAISO and IOUs should begin as quickly as possible to allow adequate time to prepare for the expected growth of BTM DER and unlock potential customer savings from reduced RA costs. Immediately following these initial discussions between the IOUs and CAISO, workshops should be held to allow stakeholders to discuss data access and DER participation in wholesale and distribution markets. CCAs and other non-IOU LSEs must play a role in these discussions to ensure that DERs are optimized to reduce RA costs and support distribution needs. For these reasons, the Commission should prioritize DER visibility to the CAISO, but reject the Joint IOUs' suggestion that stakeholder discussions are unnecessary.

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[19] Joint IOUs Opening Comments, at 34.
[20] CAISO Opening Comments, at 2.
[21] Joint CCAs' Presentation, at slides 3-4.

V. THE COMMISSION SHOULD REJECT SDG&E'S RECOMMENDATIONS TO MODIFY THE FGS REPORT TO STATE THAT FLEXIBLE LOAD ENERGIZATION IS A TEMPORARY SOLUTION AND TO NOT DEVELOP A ROADMAP FOR FLEXIBLE LOAD ENERGIZATION

The Commission should reject SDG&E's recommendations: (1) to modify the FGS Report to state that flexible load energization is merely a temporary solution[22]; and (2) to not develop a roadmap flexible load energization.[23] Flexible load energization is an important tool for reducing energization delays and should be implemented as soon as possible. The Joint IOUs' comments correctly identify that developing a roadmap for distribution-level services from flexible load energization "is core to Track 2 of the High DER proceeding."[24] The Joint IOUs' comments also proposed questions about flexible load energization to be addressed in this proceeding, including the following: "[i]f this is currently envisioned as short-term, consider the analysis of long-term."[25]

PG&E recently filed a bridging solutions strategies report describing their flexible service connection pilot program, Flex Connect, currently offered for electric vehicle charging stations.[26] The plan expands on the vision of flexible load energization as a potential long-term measure, stating:

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22 SDG&E Opening Comments, at 6-7.
23 *Id.*, at 23.
24 Joint IOUs Opening Comments, at 31.
25 *Ibid.*
26 *Bridging Solutions Strategies Compliance Report Filed by Pacific Gas and Electric Company (U 39 E),* R.21-06-017 (Dec. 16, 2024), at 3: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M549/K465/549465246.PDF.

> [w]hile flexible service connection today is intended as a temporary bridging solution, it is worth discussing with customers whether they would consider flexible service connections as a replacement for utility upgrades that allow full loading without restrictions. If flexible service were implemented as a long-term solution at scale, energy throughput on the system would increase with minimal PG&E investment requirements, contributing to neutralizing rate impacts.[27]

Similarly, SCE's bridging strategies plan describes their flexible interconnection strategy, including their current load control management system (LCMS) and their plans to deploy a DERMS to enable advanced load management capabilities:

> The expectation is, much like with the concept of Operational Flexibility generation interconnection, that a more dynamic understanding of grid constraints can be translated into a more dynamic set of requirements for customers' load management systems to follow. This will follow the same general process as the current LCMS approach but will ***adjust customer consumption limits on an ongoing basis*** based on real-time conditions, utilizing dynamic pricing, updated day ahead, or possibly rolling 24 hours ahead.[28]

Clearly, both PG&E and SCE see flexible load energization as a durable solution and are already considering deployment on a longer-term basis. There is no reason to delay the development of a roadmap for flexible load energization, considering that both PG&E and SCE have already begun planning for, or in PG&E's case, already piloting, these solutions. The Commission should reject SDG&E's recommendations to: (1) modify the FGS Report to state that flexible load energization is only a temporary solution; or (2) deprioritize developing a roadmap for distribution-level grid services from flexible load energization.

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27 *Ibid.*

28 *Southern California Edison Company's (U 338-E) Plan and Compliance Report on Bridging Strategies and Solutions*, R.21-06-017 and R.24-01-018 (Dec. 16, 2024), at 7 (emphasis added): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M550/K610/550610226.PDF.

VI. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

Leanne Bober

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

January 10, 2025

DOCKETED	
Docket Number:	23-LMS-01
Project Title:	Load Management Standards Implementation
TN #:	261140
Document Title:	23-LMS-1 CalCCA Comments on LMS SST 25 01 17
Description:	23-LMS-1 CalCCA Comments on LMS SST 25 01 17
Filer:	Shawn-Dai Linderman
Organization:	CALIFORNIA COMMUNITY CHOICE ASSOCIATION
Submitter Role:	Intervenor
Submission Date:	1/17/2025 4:36:09 PM
Docketed Date:	1/17/2025

STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *Load Management Standards Implementation*	DOCKET NO. 23-LMS-01

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE LOAD SERVING ENTITIES' OCTOBER 1, 2024, PLAN FOR A SINGLE STATEWIDE RATE ACCESS TOOL

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January 17, 2025

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STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *Load Management Standards Implementation*	DOCKET NO. 23-LMS-01

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE LOAD SERVING ENTITIES' OCTOBER 1, 2024, PLAN FOR A SINGLE STATEWIDE RATE ACCESS TOOL

The California Community Choice Association[1] (CalCCA) submits these comments in the Load Management Standards[2] (LMS) docket pursuant to the *Request for Comment on the Load Serving Entities' October 1, 2024, Plan for a Single Statewide Rate Access Tool* (the Request), dated November 15, 2024. The Request states that California Energy Commission (Commission) staff is interested in comments on the October 1, 2024, Single Statewide Tool plan[3] (SST Plan) filed jointly by the Large Investor-Owned Utilities[4] (Large IOUs), Large Publicly Owned Utilities[5]

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[1] 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.

[2] California Code of Regulations (CCR), Title 20, §§ 1621-1625.

[3] Docket 23-LMS-01, *Initial Proposed Framework for Single Statewide Standard Tool Required by California Code of Regulations, Title 20, Section 1623(c)* (Initial Proposed Framework); *IOU/POU/CCA Concept Design Document for CEC LMS Single Statewide Tool; Terms and Conditions for Use of Single Statewide Standard Tool by Third Parties* (Oct. 1, 2024) (together, the SST Plan).

[4] The Large IOUs are Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE). LMS § 1621(c)(8).

[5] The Large POUs are Los Angeles Department of Water and Power (LADWP) and Sacramento Municipal Utility District (SMUD). LMS § 1621(c)(9).

(Large POUs), and Large Community Choice Aggregators[6] (Large CCAs), as those entities are defined in the LMS (together, the Joint LSEs). Commission staff requests answers to 20 questions set forth in Attachment A, as well as any other comments, to allow planning of "next steps for the design and implementation of a statewide rate tool."

CalCCA submits these comments on behalf of its CCA members, including the Large CCAs.

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

CalCCA appreciates the targeted questions posed by Staff on the Joint LSEs' SST proposal. Equally as important as answering these questions, however, is ensuring that the Commission, staff, and all parties share a common understanding of the interaction between the SST and LMS and the problems we are collectively trying to solve. The affordability crisis also commands that the Commission adopt solutions sensitive to costs, administrative burden, and flexibility in achieving the ultimate goal – enabling customers to shift their load in response to market signals.

The SST is one of several components of the LMS scheme intended to encourage shifting of customer electric use based on programs or hourly or sub-hourly grid signals, including electricity prices. The LMS regulations require the Joint LSEs to develop and maintain the SST to enable third parties, including automated service providers (ASP), to obtain customer rate information. After retrieving their customers' rate information through the SST, and obtaining the actual rate from the Market Informed Demand Automation Server (MIDAS), the third parties

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[6] The Large CCAs are: (1) Ava Community Energy (formerly East Bay Community Energy) (Ava); (2) Central Coast Community Energy (CCCE); (3) Clean Energy Alliance (CEA); (4) Clean Power Alliance of Southern California (CPA); (4) CleanPowerSF (CPSF); (6) Marin Clean Energy (MCE); (7) Orange County Power Authority (OCPA); (8) Peninsula Clean Energy (PCE); (9) Pioneer Community Energy (Pioneer); (10) San Diego Community Power (SDCP); (11) San Jose Clean Energy (SJCE); (12) Silicon Valley Clean Energy Authority (SVCE); (13) Sonoma Clean Power (SCP); and (14) Valley Clean Energy (VCE). *Id.,* § 1621(c)(10).

can then provide grid signals to their customers, who can in turn shift load during certain conditions (*e.g.,* high price periods).

While the LMS regulations have strict and explicit requirements for the SST, which were incorporated into the October 1, 2024, SST Plan submission, the Request now states that Commission staff "will review and consider all comments *in planning next steps for the design and implementation of a statewide rate tool*."[7] In fact, the Request incorporates questions regarding an "alternative architecture" of the tool design, with potential "additional customer information (e.g., historical interval meter data)" and an adjusted "feature set" vis a vis the "initially envisioned features."[8]

CalCCA appreciates the Commission's desire to think outside the box in planning "next steps." The LMS is, in fact, at an implementation crossroads not only with the SST, but with the status of the MIDAS as well as the load serving entities' (LSEs') LMS Plans. The discussion below encourages the Commission to examine not only where LMS has been, but also how to ensure its future success. Prior to moving forward on any "next steps" for the SST, the Commission should pause, reassess current LMS implementation, and determine if the LMS scheme should be reconfigured to more effectively, and affordably, reach LMS goals. This reassessment may even require reopening and revising the LMS regulations.

In support of this "level set," the discussion below first provides the LMS background to describe the LMS requirements as well as the status of LMS implementation. CalCCA also provides the following overall recommendations regarding the LMS program, including that:

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[7] Request, Attachment A, at 3.
[8] *Id.,* Questions 6 and 18, at 3-4.

- The Commission should pause its LMS implementation to assess "next steps";
- The LMS should be reconfigured as an innovative, voluntary program to ensure the goals of the program are met;
- Functional market tools and funding should be established, in coordination with the California Public Utility Commission's (CPUC's) Demand Flexibility proceeding,[9] prior to LMS implementation; and
- LMS costs should to the greatest extent possible be funded by the profit-motivated beneficiaries of the LMS program instead of all ratepayers, preventing cost shifts and ensuring equity.

Finally, to the extent the Commission does move forward with SST development, CalCCA provides answers below to the specific questions in the Request, with the following overall recommendations:

- SST funding must be determined prior to any final decision on the SST structure;
- To the extent ratepayers are expected to fund the SST, existing systems should be used to the greatest extent possible to ensure affordability, as is proposed in the Joint LSEs' SST Plan;
- In response to the Joint LSEs' SST Plan, the Commission should require the IOUs to provide customer rate information on behalf of CCAs given IOU/CCA rate complexity and existing business rules;
- CCA data needs should be addressed if the Commission seeks additional functionalities for the SST, subject to cost and affordability considerations; and
- The Commission should require the development, maintenance, and funding of the SST by the third parties utilizing and profiting from the tool.

As the Commission and stakeholders work toward a balanced solution to achieve the LMS goals, CalCCA urges the Commission to step back and reflect on the most efficient, sensible, and cost-effective path to move forward.

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[9] *See* CPUC Rulemaking (R.) 22-07-005, *Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates*.

II. BACKGROUND

A. Load Management Standard Regulations

The LMS regulations were amended effective April 1, 2023, after a pre-rulemaking[10] and rulemaking.[11] Implementation of the amended regulations is occurring in Docket 23-LMS-01. The LMS states that it "establishes electric load management standards pursuant to section 25403.5 of the Public Resources Code [PRC]."[12] PRC section 25403.5 requires the Commission to "adopt standards by regulation for a program of electrical load management for each utility service area."[13] "Service area" is defined as "any contiguous geographic area serviced by the same electric utility."[14] While CCAs are not explicitly subject to the Commission's statutory jurisdiction under PRC section 25403.5, the Commission interprets section 25403.5 to incorporate Large CCAs into the LMS as a result of their service of customers within the utility "service area."[15]

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[10] *See* Docket 19-OIR-01.

[11] *See* Docket 21-OIR-03.

[12] LMS § 1621(a). "Load Management" is defined in the Public Resources Code as "any utility program or activity that is intended to reshape deliberately a utility's load duration curve." Pub. Res. Code § 25132.

[13] *Id.* § 25403.5(a).

[14] *Id.* § 25118. "Electric utility" is defined as "any person engaged in, or authorized to engage in, generating, transmitting, or distributing electric power by any facilities, including, but not limited to, any such person who is subject to the regulation of the Public Utilities Commission." *Id.* § 25108.

[15] CalCCA and the Large CCAs repeatedly disagreed, and continue to disagree, with the Commission's assertion of jurisdiction over CCAs based on this statutory interpretation. *See* CEC Docket 19-OIR-01, *Comments of the California Community Choice Association to the California Energy Commission on the Draft Staff Report* (June 4, 2021); Docket 21-OIR-03, *California Community Choice Association's Comments on the Proposed Amendments to the Load Management Standards Contained in the California Code of Regulations, Title 20* (Feb. 7, 2022); Docket 21-OIR-03, *California Community Choice Association's Comments on the Proposed Revisions to the Load Management Standards* (Apr. 20, 2022); Docket 21-OIR-03, *California Community Choice Association's Comments on the Proposed Revisions to the Load Management Standards (Notice of Second 15-Day Public Comment Period)* (July 21, 2022); Docket 21-OIR-03, *California Community Choice Association's Comments on the Proposed Amendments to the Load Management Standards, California Code of Regulations, Title 20 (Notice of Third 15-Day Public Comment Period)* (Sept. 27, 2022). Nevertheless, the Large CCAs continue best efforts to comply with the LMS.

The stated purpose of the LMS is to:

> establish cost-effective programs and rate structures which will encourage the use of electrical energy at off-peak hours and encourage the control of daily and seasonal peak loads to improve electric system equity, efficiency and reliability, lessen or delay the need for new electrical capacity, and reduce fossil fuel consumption and greenhouse gas emissions, thereby lowering the long-term economic and environmental costs of meeting the State's electricity needs. These load management standards do not set rates. The standards instead require that entities subject to this article offer rates or programs structured according to the requirements established herein.[16]

PRC section 25403.5 ***requires*** the LMS to be cost effective and technologically feasible.[17] The Commission states that LMS will: (1) help customers "adjust their energy use to better match the availability of clean electricity"; (2) integrate renewables on the grid and help mitigate future climate change; and (3) provide electricity bill savings when consumers opt-in to using automated load-shifting devices such as smart thermostats, appliances and other third party technologies.[18]

The LMS program includes five broad categories for implementation for the Large IOUs, Large POUs, and Large CCAs:

LMS Category	Description	LSE
(1) Marginal Cost-Based Rates/Programs	Develop, and apply to the applicable rate-approving body for approval of, hourly or sub-hourly time and location dependent **marginal cost-based rates** for each customer class that the rate-approving body determines such rates will materially reduce peak load.	IOUs, POUs, CCAs[19]

[16] LMS § 1621(a).

[17] Pub. Res. Code § 25403.5(b) ("The standards ***shall*** be cost-effective when compared with the costs for new electrical capacity, and the commission shall find them to be technologically feasible. Any expense or any capital investment required of a utility by the standards ***shall*** be an allowable expense or an allowable item in the utility rate base and ***shall*** be treated by the Public Utilities Commission as allowable in a rate proceeding.").

[18] *See* Commission LMS Website: https://www.energy.ca.gov/programs-and-topics/topics/load-flexibility/load-management-standards

[19] LMS §§ 1623(a) (Large IOUs), 1623.1(b)(1)-(2) (Large POUs, Large CCAs).

LMS Category	Description	LSE
	If after evaluation of cost effectiveness, equity, technological feasibility, benefits to the grid, and benefits to customers of marginal cost-based rates for each customer class the Large POU or Large CCA does not propose development of marginal-cost based rates, the plan is required to propose "**programs** that enable automated response to marginal cost signal(s) for each customer class" and evaluate them on the same criteria.	Only POUs and CCAs[20]
	Seek a **delay, modification, or exemption** from compliance if despite good faith efforts to comply, requiring timely compliance with the LMS requirements results in: • extreme hardship, • reduced system reliability (e.g., equity or safety) or efficiency, or • is not technologically feasible or cost-effective to implement	IOUs, POUs, CCAs[21]
(2) MIDAS	**Upload** to the Commission-maintained Market Informed Demand Automation Service (MIDAS) rate database all existing and future time-varying rates;	IOUs, POUs, CCAs[22]
(3) Single Statewide Tool	Develop a "single statewide tool for **authorized rate data access by third parties** that is compatible with each of those entities' systems"	IOUs, POUs, CCAs[23]
(4) Public Information Programs	Encourage mass-market automation of load management through **public information and programs**	IOUs, POUs, CCAs[24]
(5) LSE Compliance Plans	Submit **compliance plans** to describe how the LSE will meet the LMS goals	IOUs, POUs, CCAs[25]

The Joint LSEs began uploading time-dependent rates to MIDAS in August 2023. The SST is in development, as the Joint LSEs submitted the SST Plan on October 1, 2024, according to the LMS regulation. The LSEs have also submitted LMS compliance plans, which are currently being assessed by the Commission. As described below, each of the processes necessary for compliance with the LMS, including MIDAS, the SST, and the LMS Plans, have been fraught with inefficiencies, lack of clear guidance on funding of tools, and technological limitations.

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20 *Id.* § 1623(a)(1)(B).
21 *Id.* §§ 1621(e) (Large IOUs), 1623.1(a)(2) (Large POUs, Large CCAs).
22 *Id.* §§ 1623(b) (Large IOUs), 1623.1(c) (Large POUs, Large CCAs).
23 *Id.* § 1623(c) (Large IOUs, Large POUs, and Large CCAs).
24 *Id.* §§ 1623(d) (Large IOUs), 1623.1(b)(5) (Large POUs, Large CCAs).
25 *Id.* §§ 1621(d) (Large IOUs), 1623.1(a)(1) (Large POUs, and Large CCAs).

1. MIDAS

MIDAS is a statewide database of current and future time-dependent rates, greenhouse gas (GHG) emissions, and California Independent System Operator (CAISO) Flex Alert Signals. MIDAS was developed and is hosted by the Commission and became publicly accessible through a public application programming interface (API) in August 2021. The rate data in MIDAS must be populated and updated by LSEs. The Commission envisions end-users and their third-party ASPs accessing rate data, Flex Alerts, GHG emissions and other grid signals from MIDAS. Access to the rate information from MIDAS is provided through a rate identification number (RIN), which can be manually accessed (or potentially automatically accessed through customer devices), or through the SST. The Commission expects customers to shift load based on information gained through MIDAS.

The LSEs began uploading time-dependent rate information to MIDAS in August 2023. Beginning at that time, the Large CCAs experienced difficulties with: (1) MIDAS server fragility (MIDAS was easily overwhelmed, and dropped rates haphazardly); (2) latency (MIDAS received rates very slowly); (3) congestion (if too many uploads occur at once, MIDAS can lock up and stop responding); (4) error codes (with no description of any error); and (5) limits of data per payload (not consistent with representations of MIDAS functionalities). While MIDAS functionality has since improved, difficulties remain. Large CCAs also continue to report inefficient use of staff time and related costs to work with the difficulties presented by MIDAS. MIDAS also does not use a standardized protocol, such as OpenADR 3.0, and therefore it remains unclear as to what extent product manufacturers and ASPs will want or be able to use it. MIDAS will likely need significant additional development to fulfill its intended purpose.

2. Single Statewide Tool

While the MIDAS database holds time-dependent rates, the SST to be developed and maintained by the LSEs is to provide third parties, including ASPs, with access to their customers' rate information held by the LSEs.[26] With that customer information, the third parties then seek the corresponding rate from MIDAS to provide the price information to their customers. The third parties, therefore, are the primary beneficiaries of the SST, as noted in the Commission's Final Staff Report accompanying the adopted LMS amendments:

> The intended outcome of these proposed amendments is to facilitate load management activities by building owners. The standards form the foundation for a statewide demand automation system that aggregates and publishes time-dependent rate information from utilities. ***<u>This data can be used by mass-market end-use automation</u>*** to provide time- and location-specific demand flexibility. Such a system would enable automation markets to coalesce around agreed upon principles and consumer technologies for load management.[27]

While "mass-market end-use automation" providers (i.e., the third parties) are the intended beneficiaries of the SST, the LMS requires the Large IOUs, Large POUs, and Large CCAs to "implement and maintain the tool," without explicitly providing how the SST will be funded.[28]

The Joint LSEs are required to develop the SST compatible with each of the LSEs' systems to:

(1) **<u>Provide rate identification number(s) (RIN(s))</u>** applicable to the customer's premise(s) to third parties authorized and selected by the customer;

(2) Provide any RINs, to which the customer is **<u>eligible to be switched</u>**, to third parties authorized and selected by the customer;

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[26] *Id.* § 1623(c).

[27] Herter, Karen and Gavin Situ. 2021. *Analysis of Potential Amendments to the Load Management Standards: Load Management Rulemaking, Docket Number 19-OIR-01.* California Energy Commission. Publication Number: CEC-400-2021-003-SF, at 52 (Final Staff Report) (emphasis added).

[28] LMS § 1623(c)(3).

(3) Provide **<u>estimated average or annual bill amount(s)</u>** based on the customer's current rate and any other eligible rate(s) if the Large IOU, Large POU or Large CCA has an existing rate calculation tool and the customer is eligible for multiple rates;

(4) Enable the authorized third party to, upon the direction and consent of the customer, **<u>modify the customer's applicable rate</u>** to be reflected in the next billing cycle according to the Large IOU's, Large POU's or Large CCA's standard procedures;

(5) Incorporate reasonable and applicable **<u>cybersecurity</u>** measures;

(6) **<u>Minimize enrollment barriers</u>**; and

(7) Be **<u>accessible</u>** in a digital, machine-readable format according to best practices and standards.

As noted in the Joint LSEs' Initial Submission on the SST, the Joint LSEs engaged with CEC staff starting in September 2023 to discuss development of the SST design.[29] The Joint LSEs then engaged in a process amongst the Large IOUs, Large POUs, and Large CCAs beginning in July 2024, holding nine workshops and providing updates to the CEC prior to finalizing the SST Plan. The Joint LSEs complied with the requirement to submit the SST by October 1, 2024, for Commission approval at a Business Meeting.[30] CalCCA provides specific comments on the SST in the answers to the Commission's questions in Section IV., below.

3. LMS Plans

The LMS regulations state that LSEs are to submit LMS compliance plans to describe how the LSE plans meet the requirements of the regulations.[31] The Large CCAs submitted their first plans to their rate-approving bodies (i.e., CCA Boards) by April 1, 2024. After Board approval, the CCAs then submitted their plans to the CEC Executive Director, who is required to follow the procedures set forth in LMS section 1623.1(a)(3)(B) and review the LMS plans for

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[29] SST Plan Initial Proposed Framework, at 7-8 (describing the process culminating in the Joint LSE proposal).

[30] LMS § 1623(c)(2).

[31] *See Id.* § 1623.1(a).

consistency with section 1623.1(a)(1) and (2).[32] The rate approving body is to: (1) approve a plan that considers programs and rate structures to satisfy the requirements of section 1623.1(b)-(d); *or* (2) delay or modify compliance with sections 1623.1(b)-(c) if the rate approving body determines that the plan demonstrates hardship, reduced system reliability (e.g., equity or safety) or efficiency, technological infeasibility, or lack of cost-effectiveness.[33] However, despite all of the Large CCAs receiving individual board approval for their LMS plans, and the Large CCAs submitting the approved plans to the Executive Director, CEC staff continues its review of the plans. CEC staff has generally indicated that "approval" will be granted if the CCA agrees to participate in the CPUC's IOU dynamic pricing pilots, or their own hourly pricing pilots.[34] However, not all CCAs have determined that participation in the pilots will be beneficial or cost-effective for their customers, and not all Large IOUs currently offer a dynamic pricing pilot. Rather, some CCAs have chosen to either provide programs in response to the LMS requirements, or to seek an exemption. CalCCA is concerned with the inconsistent application and enforcement of the LMS by the CEC. As CCA governing bodies maintain sole jurisdiction over CCA rates, the CEC should simply be reviewing LMS plans for *consistency* with the LMS.

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[32] *See id.* § 1623.1(a)(3)(B) ("The Executive Director shall review plans or material plan revisions and either return them to the Large POU or the Large CCA for changes or submit them to the Commission for review and potential approval. The Executive Director shall make an initial determination whether the plan or material plan revision is consistent with the requirements of Section 1623.1(a)(1) and (2). In reviewing plans and material plan revisions, the Executive Director may request additional information or recommend changes to make it consistent with the requirements of Section 1623.1(a) (1) and (2). The Large POU or Large CCA shall respond to requests or recommendations within ninety (90) days of receipt from the Executive Director. The Executive Director shall then submit the plan or material plan revision to the Commission with a recommendation on whether to approve it.").

[33] *Id.* § 1623.1(a)(2).

[34] *See* D.24-01-032, *Decision to Expand System Reliability Pilots of Pacific Gas and Electric Company and Southern California Edison Company,* R.22-07-005 (Jan. 25, 2024) (CPUC directing PG&E and SEC to expand demand flexibility pilots, authorized in D.21-12-015, to provide system reliability benefits between June 1, 2024, and December 31, 2027).

The CEC cannot seek to utilize the LMS plans to coerce CCAs to offer specific rates or pilots or otherwise limit the jurisdiction of CCA's governing bodies.

The Large CCAs also remain concerned with the considerable staff time spent creating their plans, which have been approved by their rate approving bodies, and which cannot be changed according to CEC staff recommendations if their rate approving bodies do not find the changes cost-effective or beneficial to customers.

B. Overlap Between LMS and CPUC Demand Flexibility Proceeding, R.22-07-005

Significant overlap exists between the LMS and CPUC Demand Flexibility proceeding, R.22-07-005, in terms of both real-time pricing tools and systems, as well as pending funding considerations for the SST. As the LMS and SST planning moves forward, considerable coordination should occur between the Commission and CPUC to ensure compatibility on real-time pricing system architecture and funding sources.

1. MIDAS, SST, and the CPUC's Proposed "Price Machine"

As noted above, the MIDAS and SST are the Commission-specified tools to enable third parties to obtain customer rate and market information, to allow their customers to shift load. At the same time, the CPUC is considering a "price machine" system "to compute time-dependent, composite, dynamic electricity prices that reflect grid conditions and upload them to [MIDAS]."[35] While still pending at the CPUC, the price machine may maintain all RINs/sub-RINs. The customer information that may be incorporated into the price machine is unclear, as is the method with which the price machine will interact with the SST. All tools and systems considered by both the Commission and the CPUC should be coordinated, along with the California Independent System Operator (CAISO) if necessary, to ensure cost efficiencies and system compatibility.

35 R.22-07-005, *Track B Working Group Report and Notice of Availability* (Oct. 11, 2023), at 181.

2. LMS Tool Funding and Cost Allocation

As noted above, funding and cost allocation for the Joint LSEs development and maintenance of the SST are not explicitly addressed in the LMS. The Commission has advised CalCCA that it may not be able to fund the SST like it has funded MIDAS. The Joint LSEs stated in their SST Plan submission that they see a need for a second SST phase in this Docket to fully explore overall SST costs, cost allocation across LSEs, and regulatory approval of costs recovery, allocation, and future funding sources.[36] The SST Plan filing has an extended discussion regarding the necessity of allocating SST related costs according to principles of cost causation, and preventing cost shifts.[37]

As noted in the SST Plan filing, LMS funding questions have been raised in the CPUC's Demand Flexibility proceeding. Specifically, the Administrative Law Judge in the Demand Flexibility proceeding in an April 24, 2024, Ruling asked how the CPUC should support the implementation of the LMS.[38] Both the Large IOUs and Large CCAs provided comments, with the Large CCAs asserting (through CalCCA's comments) that LMS cost recovery (including for the SST) should be through IOU distribution rates if cost recovery is not available through non-ratepayer or Commission funds.[39] There are approximately twenty different LSEs subject to the

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36 SST Plan, Initial Proposed Framework, at 18-19.

37 *Id.* at 18-22.

38 R.22-07-005, *Administrative Law Judge's Ruling on Track B Working Group 1 Proposals and Issue 5* (Apr. 24, 2024), at Attachment A, Question 5.

39 *See California Community Choice Association's Comments on the Administrative Law Judge's Ruling on Track B Working Group 1 Proposals and Issue 5,* R.22-07-005 (May 22, 2024), at 5-7 (that LMS cost recovery on behalf of bundled and unbundled customers, including costs for the SST, should be through IOU distribution rates if cost recovery is not available through non-ratepayer or CEC funds); *see also California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling on Track B Working Group 1 Proposals and Issue 5,* R.22-07-005 (June 12, 2024), at 6-11 (stating that the CPUC should adopt the Large IOUs' categorization of LMS costs and specify from whom and how the LMS costs will be recovered from the Large IOU and Large CCA customers to prevent cost shifts). The Large IOUs also filed comments and reply comments on LMS cost issues in response to the ALJ's April 24, 2024, ruling. *See Opening Comments of Southern California Edison Company (U 338-E), Pacific Gas and*

LMS regulations, all with different processes for approving funds and allocating costs. There is no precedent that CalCCA is aware of in which twenty different LSEs have coordinated to fund, implement, and maintain a tool like the SST.[40] Adding complex and uncertain funding processes through twenty different LSEs complicates the development of the SST. Further, there should be a mechanism to recover costs to develop, implement, and maintain the SST through the third parties that use and stand to profit from the SST. As of today, the issue remains pending before the CPUC. No other guidance on funding or cost allocation for the SST has been provided by the Commission, the CPUC, or any other regulatory or governing body.

III. THE COMMISSION SHOULD PAUSE ITS LMS IMPLEMENTATION AND ASSESS "NEXT STEPS"

As part of LMS "next steps," the Commission should immediately pause LMS implementation while it reassesses whether the overall LMS program can be improved. As noted in the background section above, MIDAS as a database remains inadequate, the Commission is seeking comments on alternative SST architecture from what the regulations require for the SST, the LMS Plans have yet to be approved and continue through uncertain processes with CEC Staff, and the CPUC is in parallel considering alternative systems for dynamic pricing and LMS funding. In addition, Californians are facing an affordability crisis, exacerbated by high electric utility rates. Given the uncertainties surrounding LMS, the Commission should pause, potentially reopen the regulations for revision, and: (1) reconfigure LMS to ensure its success; (2) establish, in concert with the CPUC's Demand Flexibility proceeding, functional market tools and funding

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Electric Company (U-39), and San Diego Gas & Electric Company (U-902-E) in Response to Administrative Law Judge's Ruling on Track B Working Group 1 Proposals and Issue 5 (May 22, 2024), at 13-18; and *Reply of Southern California Edison Company (U 338-E), Pacific Gas And Electric Company (U-39), and San Diego Gas & Electric Company (U-902-E) in Response to Administrative Law Judge's Ruling on Track B Working Group 1 Proposals and Issue 5,* R.22-07-005 (June 1, 2024), at 3-5.

40 *See California Community Choice Association's Comments on the Administrative Law Judge's Ruling on Track B Working Group 1 Proposals and Issue 5,* R.22-07-005 (May 22, 2024), at 6.

prior to LMS rate or program implementation; and (3) coordinate with profit motivated third parties in developing tools for LMS implementation.

A. The LMS Should be Reconfigured as an Innovative, Voluntary Program

The LMS program should be reconfigured as an innovative, voluntary program. The overly dogmatic and prescriptive implementation of LMS regulations by CEC staff fails to recognize that many CCAs are already administering load management programs that meet the goals of the LMS – enabling customer-supported load management.[41] While some of the programs may not neatly fit into the LMS "box," they align with the spirit, and meet the goals, of the LMS. Meanwhile, the Commission is dogmatically implementing LMS requirements, *mandating* participation with strict LMS requirements, even when presented with programs meeting the spirit of the LMS. In doing so, the Commission is undermining innovation and progress of LSEs meeting the needs of their customers and the autonomy of each CCA's governing body. As a result, CalCCA recommends the Commission pause, reevaluate, and reconfigure LMS into an innovative, voluntary program.

B. Functional Market Tools and Funding Should be Established, in Coordination with the CPUC's Demand Flexibility proceeding, prior to LMS Implementation

Functional market tools and funding sources, including through coordination with the CPUC's Demand Flexibility proceeding, should be established prior to further LMS development. In fact, requiring MIDAS uploads, development of the SST, and commitment to dynamic pricing programs prior to the establishment of such market tools and funding sources has effectively put the cart before the horse. While MIDAS remains inadequate, the CPUC is considering establishing a "price machine" and other systems to enable dynamic pricing that will

41 *See* LMS Final Staff Report, at 1.

certainly overlap with LMS systems.[42] However, cost recovery and allocation for the Large IOUs and Large CCAs for the price machine, as well as the LMS MIDAS uploads and the SST, is still pending before the CPUC.[43] While the LMS steams forward, the Large IOUs and Large CCAs cannot commit to any structure for the SST until the cost recovery and allocation issues are decided. Similarly, dynamic pricing proposals pending at the CPUC will certainly impact the Large IOUs, and potentially the Large CCAs, in their development of such proposals. CalCCA urges the Commission to work closely with the CPUC to ensure "next steps" for the LMS move forward in a coordinated, effective manner.

C. Profit Motivated Third Parties Should be Encouraged to Develop, Fund, and Maintain Tools Necessary for their Customers to Shift Load

The Commission should also consider not placing cost responsibility for LMS tools, including the SST, on ratepayers when the third parties receiving the rate information through the SST are not only likely better equipped to develop the SST, but will also likely profit from the SST. The LMS regulations currently place responsibility to develop and maintain the SST on the Joint LSEs. The Joint LSEs have repeatedly stated that either the CEC or the third parties profiting from the tool should be responsible for its costs, rather than ratepayers in general (many of whom will not use or benefit from the SST). However, SST funding remains an open and critical question for moving forward with development of the SST, especially in light of the current affordability crisis for ratepayers. CalCCA encourages the Commission to clearly establish funding sources for the SST prior to further discussion on the SST structure. Funding from the SST should be sourced either from the Commission or non-ratepayers such as the third parties directly benefitting from the SST.

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42 *See* R.22-07-005, *Track B Working Group Report and Notice of Availability* (Oct. 11, 2023), at 181.

43 *See supra,* note 39.

IV. CALCCA COMMENTS IN RESPONSE TO ATTACHMENT A QUESTIONS

A. Design

1) Please identify examples of other, similar software/tools that perform this kind of task. Specifically, please identify other software that authenticates a person as an eligible customer of a business that is different from the business querying the customer's information.

CalCCA has no response at this time.

2) Do you support the statewide rate tool design as proposed by the LSEs in their October 1, 2024, filings? Why or why not? If not, what alternative architecture do you recommend?

CalCCA supports the SST Plan submitted by the Joint LSEs as responsive to LMS requirements, but with the CCA conditions as set forth in the Plan submittal. The tool as described in LMS, can vary from a robust, centralized system holding all LSE rate information, ready to compile any information requested of third parties, to a thin proxy as proposed in the SST Plan. The thin proxy will simply direct requests from third parties to the relevant LSE, which responds back through the thin proxy to the third-party request. As noted above, funding for the SST has not yet been established. If ratepayers are required to fund the SST, the thin, proxy layer, addresses affordability concerns by utilizing *existing systems* to enable third parties to access the utility rate information of their customers. However, as described below, differences remain among the IOUs and CCAs regarding functionalities of the tool, including responsibilities of the LSEs to provide the rate information.

Complexities exist for third party use of the SST on behalf of CCA "unbundled customers," requiring alternative functionalities than those originally proposed by the Large IOUs (*i.e.,* that each LSE develop systems, tools, and processes to handle providing the information through the thin SST proxy layer). "Unbundled" customer rates of the Large CCAs are comprised of both CCA generation components and IOU transmission and distribution components, creating complexity for Large CCA participation in the SST. IOU and POU rates "bundle" the generation, transmission, and distribution components, which allow for IOU and POU functions in the canonical description of the SST to be relatively straightforward. During SST development discussions, the Large IOUs and Large CCAs identified and attempted to reconcile the complexities of providing the combined CCA/IOU RINs, rate comparisons, bill comparisons, or rate change capabilities required by LMS section 1623(c) for unbundled customers. Since CCA customers are also *de facto* IOU customers, the Large CCAs recommend that when a Third Party engages with the SST on behalf of an unbundled customer, the first "stop" should be the IOU. The IOU can then interact for both the CCA generation component, and IOU transmission and distribution component, with the SST on behalf of the IOU and Large CCA for that unbundled customer. To ensure cost effectiveness and ratepayer affordability – by not requesting CCAs to build duplicative systems that increase ratepayer costs – the Large CCAs recommend the existing "business rules" and billing services agreements between the IOUs and CCAs be utilized to govern the provision of services (providing RINs, rate/bill comparison, rate change) by the Large IOUs to the Large CCAs for the SST. The direct interface of the IOU on behalf of the CCA will result in the Large CCAs generally not interfacing directly with the SST, unless an individual CCA chooses such direct contact with the SST.

Additional details of such functionalities between the Large IOUs and Large CCAs for the SST remain unresolved, such as the IOUs storing (or "caching") RINS on behalf of the Large CCAs. PG&E has stated that it already caches RINs for CCAs in its territory, and therefore will be able to provide RINs on behalf of unbundled customers of those CCAs. However, SCE and SDG&E have stated that they do not currently cache the unbundled customer RINs, and therefore would need to build systems to cache the RINs (which are already provided to the

IOUs by the CCAs in their service territories) for inclusion on customers' monthly bills. In addition, it should be noted that most, if not all, Large CCAs do not currently have existing rate or bill comparison tools as likely envisioned by the LMS regulations.

3) What aspects of the LSEs' proposed design do you support, and think will work well? Why?

See CalCCA's response to Question 2, above.

4) Do you recommend a different approach for sharing a customer's rate information with service providers that the customer explicitly authorizes?

CalCCA supports the Joint LSEs' submission, with the conditions and caveats set forth therein.

5) How do you view the proposed ease of access for rate customers? Are there areas where ease of use could be improved or barriers reduced?

The SST Plan was submitted in response to the LMS regulations, which do not require a customer-facing tool. Rather, the regulations require third party access to customer rate information through the SST. If the Commission changes the requirements of the tool, significant modifications to the SST Plan will be necessary to ensure customer authentication, validation, and security.

6) Should any additional customer information (e.g., historical interval meter data) be available through the statewide rate tool? If so, what? At what frequency should any additional data be available and at what frequency should it be updated? For example, "The statewide rate tool should include hourly meter data from the customer's meter and hourly distribution-level congestion measurement for the customer's meter. These data should be updated daily such that the previous day's data is always available."

As noted in Section III., above, CalCCA recommends the Commission pause the LMS implementation while it reassesses LMS requirements, including whether the SST as framed in the regulations meets the needs of third parties, LSEs, and customers. This question specifically raises the possibility of additional functionalities for the SST, which are not currently scoped in the regulations. As stated above, the Joint LSEs' SST Plan was developed in response to the existing LMS requirements and does not envision any additional requirements. The Joint LSEs were careful to meet the requirements of the LMS regulations, while ensuring cost-effectiveness through the use of existing IOU data systems.

If the Commission intends to require additional functionalities in the SST, the Large CCAs note that obtaining timely and accurate data to cost efficiently and adequately serve customers has always been a primary concern of CCAs. The CCAs and CalCCA have raised in many forums their challenges obtaining needed customer, billing, and other data from the IOUs.[44] In fact, in addition to the LMS cost issues, currently pending before the CPUC in the Demand Flexibility proceeding are CalCCA proposals to improve the data (such as for customer usage, interval billing data, demand response program enrollment) timeliness and accuracy provided by the IOUs to the CCAs. Therefore, as part of its reassessment of LMS, the Commission should consider whether additional data functionalities should be added in connection with LMS, and/or in coordination with the CPUC proceedings.

B. Authentication, Customer Authorization, Privacy and Security

7) What approach do you recommend for authentication? Single sign on, one time passcode, or something else?

CalCCA supports the Joint LSEs' submission, with the conditions and caveats set forth therein.

8) What are the privacy and security concerns for the statewide rate tool? How should they be addressed?

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[44] Data challenges and issues are currently being addressed in several CPUC proceedings, including but not limited to: (1) R.22-07-005, Demand Flexibility; (2) R.22-11-013, Distributed Energy Resources; (3) R.21-06-017, High DER; and (4) A.24-10-014, PG&E Billing Modernization Initiative.

As noted in response to question 5, above, the LMS regulations do not anticipate direct customer access through the SST. Rather, third parties will access customer rate information only after getting consent from the customer to access such data. CalCCA supports the Joint LSEs' submission, which addresses cybersecurity and privacy concerns.

9) How should service providers register to gain access to the statewide rate tool? What are appropriate and reasonable requirements for access (or reasons to deny access)? Are there examples that could be followed?

CalCCA supports the Joint LSEs' submission, with the conditions and caveats set forth therein.

10) Does the LSEs' proposal appropriately address customer authorization? Why or why not? If not, what approaches do you recommend for ensuring the customer is authorizing the service provider to look up their rate information?

The Joint LSEs' SST Plan does address customer authorization for third parties to access their rate information from the Joint LSEs, as well as authorization to perform the other requirements of the SST (i.e., rate comparison or rate change). CalCCA supports the Joint LSEs' submission, with the conditions and caveats set forth therein.

C. Cost

11) How can the cost of development, deployment, and maintenance be reduced?

The Joint LSEs' SST Plan was developed to comply with the existing LMS regulations in the most cost-effective manner possible. Therefore, the LSEs chose to incorporate existing data systems into the functionality of the SST, and only require a thin proxy level SST to be built to channel requests and information between third parties and LSEs. If requirements for the SST are modified, CalCCA recommends that the SST remain simple, streamlined, and efficient, keeping operational and maintenance costs contained. CalCCA also recommends that the third parties profiting from the SST both fund the development and maintenance of the tool, as explained in Section III.C., above.

12) Roughly, what is the total cost you would expect for developing, implementing, and maintaining the statewide rate tool? What experience or examples do you base your estimate on?

The total cost for the SST can vary widely depending primarily on whether existing tools are utilized, or if new tools must be developed. The Joint LSEs developed the SST Plan to utilize existing data access tools to the greatest extent possible, to ensure cost-effectiveness and affordability for ratepayers. CalCCA has no additional comment at this time as to the "total cost" for the SST.

D. Terms and Conditions

13) Do you support the terms and conditions in the LSEs' submission? If not, what changes would you recommend?

CalCCA supports the Joint LSEs' submission, with the conditions and caveats set forth therein.

14) What are appropriate limitations or requirements for data sharing, retention, storage, and privacy?

CalCCA supports the Joint LSEs' submission, with the conditions and caveats set forth therein.

E. Usage and Governance

15) The load management standards put responsibility for building and maintaining the statewide rate tool with the utilities and CCAs. Is there a more efficient way to build the tool or achieve its goals?

The Joint LSEs developed the SST Plan in light of the current LMS regulations. As noted in Section III.C. above, third parties profiting from the SST and who likely have greater expertise and knowledge as to appropriate technologies to respond to what their customers are seeking may be in a better position to develop and fund the tool. The Commission should consider requiring third parties to fund the tool, either directly through a change to the regulations, or through usage or flat fees if the Joint LSEs are required to build and maintain the tool.

16) **How useful do you expect the tool to be to users, for example automation service providers? What are the most valuable use cases for the tool? Should costs be imposed on automation service providers to cover usage or for a service level agreement to help cover the cost of maintenance?**

See response to question 15, above.

17) **What should be the funding source for the development and maintenance of the tool?**

See response to question 15, above. Also as noted in Section II.B.2., above, as it stands now funding for the SST is uncertain. The Joint CCAs have recommended in the Demand Flexibility proceeding, and continue to recommend here, that non-ratepayers or the Commission, or third parties profiting from the tool, fund the tool.

18) **Should the tool incorporate all initially envisioned features or should the feature set be adjusted? For example, "Rate change capability is nice to have, but not required for my company's load flexibility and VPP offerings. We would benefit more by having additional customer and grid data available through the tool."**

The SST Plan was submitted in compliance with the current LMS regulations. Any further required functionalities for the SST will require the Commission to modify the regulations through a rulemaking. As set forth in Section III., above, CalCCA recommends that the Commission pause its implementation of the LMS, including development of the SST, to consider questions as to whether the current regulations satisfy the needs and goals of the LMS program.

19) **If the statewide rate tool is not developed, what effects do you expect this to have on automation service providers, electricity customers, and statewide adoption of load flexibility?**

As set forth in Section III., above, the Commission should consider this question as part of a holistic review of whether the current LMS regulatory requirements, including the SST, are necessary to fulfill the goals of the LMS program.

20) Do you have any concerns about equity or equal access? If so, how can these be addressed?

Equity and equal access should be a core component of the Commission's reassessment of the LMS. Requiring all ratepayers to fund LMS tools when only certain customers will access the LMS program through third parties raises significant equity and equal access concerns. Most customers are unlikely or unable to adopt the technology needed to participate in dynamic pricing, and therefore requiring those customers to pay for the systems supporting that technology is a cost-shift and patently unfair.

V. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the comments herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

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

January 17, 2025

Pacific Gas and Electric Company

Sidney Bob Dietz II
Director
Regulatory Relations

Pacific Gas and Electric Company
300 Lakeside Drive
Oakland, CA 94612

January 17, 2025

Advice 7486-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

<u>Subject:</u> **PG&E Advice Letter to Establish Eligible Demand Response Program Lists, in Compliance with D.23-12-005 and D.24-03-071.**

Purpose

Pacific Gas and Electric Company (PG&E) hereby submits this Tier 2 Advice Letter (AL) in compliance with Ordering Paragraph (OP) 10 of California Public Utilities Commission (Commission or CPUC) Decision (D.) 23-12-005, *Decision Directing Certain Investor-Owned Utilities' Demand Response Programs, Pilots, and Budgets for the Years 2024-2027* (the Decision). The Commission ordered PG&E, Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) to each submit Tier 2 ALs - on an as needed basis and in coordination with community choice aggregators (CCAs)[1]– to establish and update the eligible Demand Response (DR) program lists, for the purposes of determining what a "qualified" DR program is, to satisfy DR incentive conditions. This AL proposes to add Marin Clean Energy (MCE)'s Peak Flex Market program to the list of qualifying DR programs.

D.24-03-071, *Decision Implementing Assembly Bill 209 and Improving Self-Generation Incentive Program Equity Outcomes*, also ordered that Self-Generation Incentive Program (SGIP) Program Administrators (PAs) "must ensure that incentive applicants are required to enroll in an approved qualified Demand Response program as described in Appendix E and Section 12.3 of this Decision".[2] The Commission specified that the list of qualified DR programs in D.24-03-071, Appendix E (Updated List of Qualified DR Programs for Meeting SGIP Requirement), is "a sub-set of the qualified DR programs that meet criteria established in D.23-12-005 that best serves SGIP program implementation",[3] and could be updated by "the IOUs as per D.23-12-005 direction, or by the SGIP PAs through Tier 2 Advice Letter".[4] To that end, this filing also proposes to add MCE's Peak Flex Market program to Appendix E.

[1] D.23-12-005, p.25.
[2] D.24-03-71, OP 21.
[3] D.24-03-071, p.75.
[4] D.24-03-071, p.76.

In Attachment 1 to this AL, PG&E provides supporting documents on behalf of MCE for the Commission to use in their determination of DR program eligibility. Via this AL, non-Investor-Owned Utility (IOU) PAs have a vehicle to provide the necessary program documentation to determine program eligibility, in compliance with Commission guidance.[5] PG&E is responsible for the accurate representation of PG&E programs and defers to Commission staff review to determine whether non-IOU PA programs meet eligibility criteria. In compliance with D.23-12-005, PG&E coordinated with MCE on the submission of this AL.[6]

Background

I. DEMAND RESPONSE

On December 20, 2023, the Commission issued D.23-12-005, *Decision Directing Certain Investor-Owned Utilities' Demand Response Programs, Pilots, and Budgets for the Years 2024-2027*. In D.23-12-005, the Commission authorized the IOUs' DR program portfolios for years 2024 – 2027, and established a new definition of "qualified" DR program[7] to satisfy a program enrollment requirement as condition of a customer receiving an incentive or rebate.[8] The Commission's detailed definition follows:

1. Economic supply-side market integrated DR programs counted for Resource Adequacy (RA) irrespective of whether the administrator is an IOU, Community Choice Aggregator (CCA) or third-party Demand Response Provider (DRP).
2. Load modifying DR programs that satisfy the following two requirements:
    a. The program is indirectly integrated with the California Independent System Operator (CAISO) energy market such that the program's dispatch signal is linked to the energy prices in the Day-Ahead or real-time market – operational domain.
    b. The program's load impact is counted towards RA obligations directly or indirectly through an approved process [such as, via a process for reducing RA obligations by integrating the program's load impact with the California Energy Commission's (CEC's) peak forecasts] – planning domain.
3. Any DR pilot authorized and designated by the Commission in a DR proceeding including R.22-07-005 as a "qualified" DR program eligible to meet the DR enrollment requirement.
4. Critical Peak Pricing (CPP) or Peak Day Pricing (PDP). These options, which at this time do not meet requirement 2a above, shall be discontinued as a "qualified" DR program if they still do not meet requirements listed here when

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[5] D.23-12-005, OP 10 and D,24-03-71, OP 21.
[6] D.23-12-005, p. 25.
[7] D.23-12-005, Conclusions of Law (COL) 4 and 5; Attachment 1.
[8] D.23-12-005, p. 22.

the dynamic rate(s) under consideration in R.22-07-005 (to comply with CEC adopted Load Management Standards[9] are made available to customers.

D.23-12-005 directed[10] IOUs and Load Serving Entities (LSEs) to file Tier 2 advice letters for the ministerial task of identifying DR programs that meet the requirements listed above on an as needed basis. IOUs and CCAs shall coordinate advice letter submissions to maintain a single master list per service territory. If a non-DR proceeding happens to develop a DR program that meets the requirements here, LSEs may reflect that in advice letter updates.[11]

D.23-12-005 also noted that the above language was adopted to define is a ‘qualified’ DR program for purposes of determining what DR programs customers should enroll in if the Commission requires such enrollment as an eligibility condition for a customer’s participation in a non-DR program, such as SGIP in the example above. Advice letters with the qualified program list should note the recommendation from above, that the non-DR proceedings using the qualified programs list should include an exemption from a DR program enrollment requirement for any customer that has no enrollment option on the list.[12]

II. DISTRIBUTED GENERATION

On March 22, 2024, the Commission issued D.24-03-071, *Decision Implementing Assembly Bill 209 and Improving Self-Generation Incentive Program Equity Outcomes*, which ordered that SGIP PAs “must ensure that incentive applicants are required to enroll in an approved qualified Demand Response program as described in Appendix E and Section 12.3 of this Decision”.[13] D.24-03-071 addressed party comments noting a need for consistency in “qualified” DR criteria across proceedings[14], and clarified that the “qualified” DR master list described in D.23-12-005 (and in this AL, in Section I, above), was intended to provide “a basis to select a subset of DR programs we deem appropriate for SGIP energy storage incentive recipients”.[15]

D.24-037-071 established the following criteria[16] for SGIP participant enrollment in “qualified” DR programs:

1. All host customers in any storage budget category receiving SGIP incentives shall be required to enroll in a qualified DR program listed in Appendix E. This

[9] California Code of Regulations – Title 20, Article 5, Section 1623
[10] D.23-12-005, OP 10.
[11] D.23-12-005, p.25.
[12] D.23-12-005, pp. 25-26.
[13] D.24-03-71, OP 21.
[14] D.23-04-071, p.95
[15] Ibid.
[16] D.24-03-027, pp.74-76, 94.

is a sub-set of the qualified DR programs that meet criteria established in D.23-12-005 that best serves SGIP program implementation.

2. Enrollment and participation in a qualified DR program must be maintained for a project's 10-year permanency period. The SGIP participant may disenroll from an approved qualified DR program to join another approved DR program but must always be enrolled in a SGIP qualified DR program.
3. This list of qualified DR programs will be maintained by the PAs on the SGIP website and updated as the list of "qualified" DR programs gets updated by the Commission or the IOUs as per D.23-12-005 direction, or by the SGIP PAs through Tier 2 Advice Letter.
4. SGIP PAs are directed to request to add to the list any qualified DR programs that may be offered to statewide customers by other non-IOU electric providers.
5. PAs, in consultation with the SGIP working group, may exempt an applicant from this DR participation requirement if:
    a. Non-IOU customers do not have access to qualified DR programs; or
    b. Customers would have to forfeit a low-income rate to join a DR program.
6. Enrollment in the Emergency Load Reduction Program (ELRP) does not satisfy this requirement, but dual enrollment in ELRP in addition to one of the eligible qualified DR programs is allowed, as consistent with applicable DR dual enrollment rules.
7. For SGIP participants in POU service territories, an SGIP approved qualified DR program should conform to the following:
    a. the storage device would shift onsite energy use to off-peak time periods or reduce demand from the grid by offsetting or lowering some (or all) of the customer's onsite energy demand,
    b. the DR program is not a Reliability Demand Response Resource (RDRR) that is use-limited; and
    c. the load impact from the storage device can be accurately measured and evaluated.
8. SGIP approved qualified DR programs must provide verifiable load drop for the storage device supported by the SGIP incentive.
9. SGIP approved qualified DR programs must be simple for participants to enroll and participate in.

D.24-03-027 also affirmed qualifying DR requirements from D.23-12-004, regarding the SGIP Heat Pump Water Heater (HPWH) program, which stated that for SGIP participants in Publicly Owned Utility (POU) service territories,

> "an SGIP approved qualified DR program is one that would use the storage device to (1) shifts onsite energy use to off-peak time periods or reduces demand from the grid by offsetting or lowering some or all of the customer's onsite energy demand, (2) is not an emergency DR program; and (3) the load impact from the storage device can be accurately measured and evaluated."[17]

[17] D.24-03-071, p.94 and Attachment E.

To demonstrate the Peak Flex Market program's qualifications using the criteria described above, MCE has provided the factual representations of its DR program, below and in Attachment 1. In compliance with D.23-12-005[18], PG&E coordinated with MCE to develop the content of this AL, which herein contains MCE's description and argument for Peak Flex Market's approval as a qualifying DR program. MCE has approved the content of this AL for submission by PG&E.

MCE Peak Flex Market Program's Eligibility for Qualified Demand Response

MCE administers a load flexibility program—the Peak Flex Market program (formerly Peak FLEXmarket program).[19] MCE started operating and self-funding the Peak Flex Market program in 2021 as a "single season"[20] summer program (June 1 to October 31) focused on reducing peak electric demand from 4pm - 9pm Pacific Standard Time (PST) through load shifting and demand response events. In D.21-12-011, *Decision on Energy Efficiency Actions to Enhance Summer 2022 and 2023 Electric Reliability*, the Commission approved MCE's use of unspent energy efficiency (EE) funds to continue its Peak FLEXmarket program operation in support of summer reliability goals in program years (PYs) 2022 and 2023.[21]

MCE evolved the program in 2024, with updated offerings and a return to self-funding. In 2024, the Peak Flex Market program provided incentives for demand response events only, based on the CAISO market price during the evening peak hours. MCE submits it will be able to demonstrate customer enrollment in the Peak Flex Market program, including enrollment in the demand response events track of the program, to SGIP PAs. MCE's Peak Flex Market program can be further reviewed in Attachment 1 to this filing.

Demand Response Qualifications

MCE's Peak Flex Market program satisfies the eligibility requirements of D.23-12-005 as follows:[22]

2. Load modifying DR programs that satisfy the following two requirements:
    a. The program is indirectly integrated with the California Independent System Operator (CAISO) energy market such that the program's dispatch signal is linked to the energy prices in the Day-Ahead or real-time market – operational domain.

[18] D.23-12-005, p. 25.
[19] https://mcecleanenergy.org/peak-flex-market/.
[20] "Single season" refers to projects shows impacts are limited to the summer peak timeframe in which they were measured, and for which there is no effective useful life, which is a dominate driver of TSB value in energy efficiency.
[21] *See* D.21-12-011 *Energy Efficiency Actions to Enhance Summer 2022 and 2023 Electric Reliability OP 2* at p. 60.
[22] D.23-12-005, Attachment 1.

MCE designed and implements the Peak Flex Market program's dispatch signal based on its ongoing monitoring of CAISO's Day-Ahead Market (DAM) prices. MCE may call an event if at least two consecutive hours in CAISO's DAM exceed $300. Each event will be a minimum of two hours. If only one hour exceeds $300, MCE will not call an event. If there are more than two hours above $300, all hours exceeding this price will be called, with a maximum of five hours. MCE may choose to change this threshold based on current summer conditions.

b. The program's load impact is counted towards RA obligations directly or indirectly through an approved process [such as, via a process for reducing RA obligations by integrating the program's load impact with the California Energy Commission's (CEC's) peak forecasts] – planning domain.

MCE includes anticipated Peak Flex Market program impacts into its peak forecasts and resource adequacy submissions.

MCE included its Peak Flex Market program impacts into:

- MCE's 2022 Resource Adequacy Demand Forecast;[23]
- MCE's 2023 Electricity Demand Forecast - Integrated Energy Policy Report;[24]
- MCE's 2023 Resource Adequacy Demand Forecast;[25]
- MCE's 2024 Resource Adequacy Demand Forecast;[26]
- MCE's 2025 Resource Adequacy Demand Forecast.[27]

<u>Distributed Generation Qualifications</u>

MCE's Peak Flex Market Program satisfies the eligibility requirements of D.24-03-071[28] as follows:

8. SGIP approved qualified DR programs must provide verifiable load drop using the storage device support by the SGIP incentive

MCE submits it can confirm verifiable load drop of Peak Flex Market program participants with batteries in satisfaction of this requirement.[29] Supporting documentation regarding MCE's Peak Flex Market program can be further reviewed in Attachment 1 to this filing.

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[23] R.19-11-009.
[24] *See* CEC, 23-IEPR-02 Docket Card available at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-02.
[25] R.19-11-009.
[26] Ibid.
[27] Ibid.
[28] D.24-037-071, p.74, 94.
[29] *See* MCE Peak Flex Market Program, Implementation Plan Program Manual Measurement & Verification Plan, June 2024, pp. 16, 37 (discussion of storage device telemetry).

9. SGIP approved qualified DR programs must be simple for participants to enroll and participate in.

MCE designed the Peak Flex Market program to be very simple and efficient for participants. Aggregators collect information from participants and enroll projects. Additional enrollment and participation information is available in Attachment 1 to this filing.[30]

MCE presented information to Energy Division staff on its Peak Flex Market program and how it satisfies qualified demand response requirements on November 20, 2024. MCE submitted additional information on its Peak Flex Market program to Energy Division staff via email upon request.

Protests

Anyone wishing to protest this submittal may do so by letter sent electronically via E-mail, no later than **February 6**, **2025**, which is 20 days after the date of this submittal. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
E-mail: EDTariffUnit@cpuc.ca.gov

The protest shall also be electronically sent to PG&E via E-mail at the address shown below on the same date it is electronically delivered to the Commission:

Sidney Bob Dietz II
Director, Regulatory Relations
c/o Megan Lawson
E-mail: PGETariffs@pge.com

In addition, please send protests and all other correspondence regarding this AL electronically to the attention of:

Wade Stano
Senior Policy Counsel, MCE
Email: wstano@mcecleanenergy.org

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name and e-mail address of the protestant; and

[30] MCE's Peak Flex Market Program: Implementation Plan, Program Manual Measurement & Verification Plan, pp. 12-17.

statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

Effective Date

Pursuant to General Order (GO) 96-B, Rule 5.2, and OP 10 of D.23-12-005, this advice letter is submitted with a Tier 2 designation. PG&E requests that this Tier 2 advice submittal become effective on regular notice, **February 16**, **2025**, which is 30 calendar days after the date of submittal.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically to parties shown on the attached list and the parties on the service list for A.22-05-002 and R.20-05-012. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Sidney Bob Dietz II
Director, Regulatory Relations
CPUC Communications

Attachments:

- Attachment 1 - MCE Peak Flex Market Implementation Plan, Program Manual, Measurement & Verification Plan.

cc: Service List A.22-05-002 and R.20-05-012.

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (U 39 E)

Utility type:
- ☑ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Michael Finnerty
Phone #: (279) 789-6216
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: michael.finnerty@pge.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 7486-E

Tier Designation: 2

Subject of AL: PG&E Advice Letter to Establish Eligible Demand Response Program Lists, in Compliance with D.23-12-005 and D.24-03-071.

Keywords (choose from CPUC listing): Compliance

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.23-12-005, D.24-03-071

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution required? ☐ Yes ☑ No

Requested effective date: 2/16/25

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Sidney Bob Dietz II, c/o Megan Lawson
Title: Director, Regulatory Relations
Utility/Entity Name: Pacific Gas and Electric Company

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email: PGETariffs@pge.com

Contact Name:
Title:
Utility/Entity Name:

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email:

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

<u>Attachment 1</u>

MCE Peak Flex Market Implementation Plan, Program Manual, Measurement & Verification Plan

MCE

Peak Flex Market Program

Implementation Plan

Program Manual

Measurement & Verification Plan

MCE20

June 1, 2024

Version 5

Table of Contents

MCE Peak Flex Market Program Implementation Plan

The following information is provided to the CPUC and other interested stakeholders in accordance with CPUC decisions and Staff guidance.[1]

Program Overview

Program Savings

1. Program and/or Sub-Program Name: **Peak Flex Market**
2. Program / Sub-Program ID number: **MCE20**
3. Program / Sub-program Goss Impacts Table:

Metric	**2024**	**2025**
Demand Response Event Reduction (MW)*	6.8	20.3
Peak Demand Impacts (MW) (Net)*	3.5	10.5
Net Peak Demand Impacts (MW) (Net)*	4.4	13.1
Peak MWh Savings (Net)	1,300	3,800

*MW estimates are an average value over the given measurement period. Demand Response Event Reduction is defined as the sum of all MWh divided by sum of all hours for all DR events during the months of June 1 and October 31. The Peak Demand Impacts value is the average MWh/h for the period of 4-9pm during any day between June 1 and September 30 except for event days. The Net Peak Demand Impacts value is the average MWh/h for the period of 7-9pm during any day between June 1 and October 31, except for event days.

4. Program / Sub-Program Cost Effectiveness (TRC): **N/A**
5. Program / Sub-Program Cost Effectiveness (PAC): **N/A**
6. Type of Program / Sub-Program Implementer: **Third Party Delivered**
7. Market Sector(s): **Residential, Commercial, Agricultural and Industrial**
8. Program / Sub-program Type: **Resource Acquisition**
9. Market channel(s): **Downstream**

[1] D.15-10-028 at 43 and D.21-12-011.

Implementation Plan Narrative

1. Program Description

The Peak Flex program is designed to realize demand reduction during peak events by enrolling flexible loads for the summers of 2024 - 2026. MCE's demand management focused Flex Market program offers a flexible path for aggregators[2] of commercial, industrial, agricultural and residential customers to bridge the gap of customer needs, MCE's resource needs, and summer grid reliability. This summer peak focused program design will help meet MCE's goals and optimize energy usage for customers. Performance incentives with enhanced peak rates will push aggregators to deliver maximum savings and optimized load shapes that maximize system benefits during summer peak (4-9pm) and net peak periods (7-9pm), focusing on demand management interventions that bring additional capacity for flexibility beyond long-term energy efficiency (EE).

The Peak Flex Market will operate in parallel and complement MCE's Commercial Efficiency Market[3] and Residential Efficiency Market[4] programs. Collectively these three programs are known as MCE's "Marketplace" programs. The two Efficiency Market programs are mainly focused on delivering longer-term EE projects, whereas the Peak Flex Market will primarily focus on demand response to deliver peak load reductions when the grid is most constrained (i.e., from June 1 through October 31 each year).

The Peak Flex Market program is designed to facilitate an open market of qualified aggregators, each with one or more portfolios of projects delivering demand flexibility solutions designed to target peak and net peak demand windows through the summer. The program is also structured such that MCE can act as an aggregator of select customers, prioritizing outreach to high-potential commercial/industrial customers.

For summer 2024, the Peak Flex program will focus exclusively on event-based reductions. The program will also demand response events during peak hours when the grid is most constrained. The program anticipates calling a minimum of seven events over the course of the summer. Demand response event days will mostly align with California Independent System Operator's (ISO) Flex Alerts and high day ahead market prices. Events can be called on weekdays and weekends.[5] MCE may also elect to call demand response events during

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[2] Aggregators - referred to as implementers in D-21-12-011 - are participating vendors or program partners who generate energy efficiency and/or demand savings for an aggregated group of customers.

[3] MCE, *Commercial Efficiency Market Program Implementation Plan*, February 7, 2022
[4] MCE, *Residential Efficiency Market Program Implementation Program*, April 1, 2022
[5] Flex Alerts Website, Accessed May 29, 2024

forecasted energy supply shortfalls or weather-related emergencies, and for a limited number of test events during the summer period. Details on event triggers are located in the Event Trigger section below. The program will strive to notify participants via email within 24 hours of each event but does not guarantee event notification lead time.[6] Event length, number of hours per event, may vary based on grid conditions but will fall within peak hours (4pm - 9pm) and will typically last for 2 to 3 hours, starting and ending on the hour. MCE reserves the right to call events for longer periods due to market conditions. Aggregator compensation for summer 2024 will equal $2,000 / MWh with settlement occurring at the end of the summer season. The M&V plan provides additional detail on the calculation of performance and aggregator settlement.

MCE will contract with a single third party, AESC, as an implementation partner. AESC and it's teaming partners, Demand Side Analytics, Resource Innovations, and ASK Energy, are tasked with relationship management and enrollment of aggregators, determining customer eligibility, processing program applications, analytics, determining payments to aggregators, M&V and more. Aggregators identify and recruit customers and help them plan and execute their energy reduction plans on event days. The AESC team will estimate performance, calculate compensation, and report the results to MCE and the aggregators. MCE will pay aggregators in Q4, based on the impacts achieved and the performance for each aggregator's portfolio.

Under the program, all aggregator payments are tied to the delivery of value during summer peak hours. Aggregators will be compensated on a flat $2,000 per MWh reduced during Peak Flex events. Aggregators cannot be penalized for a lack of performance but can be compensated $0 for the summer season if the net energy reduction of their portfolio is less than or equal to 0 MWh during Peak Flex events. Each Aggregator portfolio can opt-out of an event, given they communicate this to MCE/AESC at least 5 hours before the event. If an aggregator alerts MCE/AESC prior to the Peak Flex event start time that they intend to opt-out of the event, the aggregator's entire portfolio is omitted from the performance calculations for that event. See more details in the Opt-out section of the M&V plan.

2. Program Delivery and Customer Services

The core strategy of the Peak Flex Market is simplification and flexibility to quickly bring assets online to deliver value to MCE and its customers. By setting a price point and the expected event parameters, the Peak Flex sends a clear signal to the market without prescribing the mechanism by which load reductions are achieved. Qualified aggregators will have the

[6] CAISO Flex Alert notifications can be issued with less than 24 hours' notice to the public and therefore the program will do its best to relay available information as soon as possible. For details on Flex Alert notification and system emergency protocols, see: http://www.caiso.com/Documents/4420.pdf

flexibility to meet residential, commercial, agricultural and industrial customers where they are at in terms of energy needs, technology fit, and cost. Rather than a prescriptive set of program offerings, aggregators will develop their offerings to fit their customers and domain expertise to maximize benefits to MCE, the grid and to the customer.

Aggregators will have full flexibility to propose services, tools, and interventions (as defined in the "Eligibility" and "Qualifying Measures" section in the attached M&V plan) to customers to encourage adoption, effectuate consumption changes, and manage energy. The AESC team will provide core services and tools to MCE and aggregators in the form of an operational platform to identify, enroll, track, and settle the demand flexibility resources delivered through this program.

In addition to traditional aggregators, MCE will also act as an aggregator of select non-residential customers to participate in the program. In this role, MCE will support high-value and high-impact customers to generate additional load reduction and grid benefits. MCE will act as an aggregator and directly recruit these high-value customers. The AESC tea m will provide site-level performance results which MCE may choose to leverage when settling with participants.

This program is not designed to specifically address hard-to-reach customer segments, but it is flexible and is a viable program for doing so. If aggregators have a business model that can target this customer segment effectively, they will be highly valuable participants in the Marketplace.

3. Program Design and Best Practices

This section is not applicable.

4. Innovation

This section is not applicable.

5. Metrics

The primary metrics for tracking program progress will be the demand and net energy savings achieved (kW, kWh).

MCE proposes the tracking of the following program metrics in the monthly reports for enrolled sites:

- Program metrics
    - Number of participating aggregators

    - Number of residential and non-residential sites
    - Total energy usage of participating sites during events (kWh)
    - Estimated Budget based on estimated percent participation per cohort
- Performance Metrics
    - Total peak energy savings achieved for each month to date (kWh)
    - Percent energy savings during each event and across all events in a month (kWh)
    - Average demand reduction during each event and across all events in a month (kWh, kW)
    - Maximum demand reduction achieved over 1 event hour for each month, including the day and hour (kW)
    - Maximum demand reduction achieved during any hour of each called event (kW) (same as above)

These metrics may be modified based on MCE input and final program reporting requirements.

6. To-Code Savings

This section is not applicable.

7. Workforce Education and Training

The Peak Flex Market program does not have an explicit workforce education and training component.

8. Workforce Standards

This section is not applicable.

9. Disadvantaged Worker Plan

The Peak Flex Market program does not explicitly address disadvantaged workers.

10. Additional information

This section is not applicable.

Supporting Documents

1. Program Manuals and Program Rules

The program manual and rules are provided with this implementation plan and are integrated into the Peak Flex Market web page, found at https://www.aesc-inc.com/mce-peak-flex/. Additional information and eligibility requirements are found in the program M&V plan.

2. Program Theory and Program Logic Model

This section is not applicable.

3. Process Flow Chart

This section is not applicable

4. Incentive Tables, Workpapers, Software Tools

The Peak Flex Market program does not have fixed measures or incentives. Workpapers are not part of the program plan.

Pre-intervention demand reduction estimates will be reviewed by the AESC team. Since demand reduction forecasts are not foundational to the Aggregator payments, review is focused on ensuring customers are getting reasonable estimates of demand reduction potential so that MCE can have confidence in forecasted impacts and manage performance payment budgets.

For demand response events, a rate of $2,000 /MWh will be applied. Incentives and costs presented to the customer are at the discretion of the aggregator. For MCE aggregated customers, the incentive will be passed directly to the customer.

5. Quantitative Program Targets

Metric	**2024**	**2025**
Demand Response Event Reduction (MW)*	6.8	20.3
Load Shift Reduction (MW)*		
Peak Demand Impacts (MW) (Net)*	3.5	10.5

Net Peak Demand Impacts (MW) (Net)*	4.4	13.1
Peak MWh Savings (Net)	1,300	3,800
Net Peak MWh Savings (Net)	1,100	3,200

*MW estimates are an average value over the given measurement period. Demand Response Event Reduction is defined as the sum of all MWh divided by sum of all hours for all DR events during the months of June 1 and October 31st. The Peak Demand Impacts value is the average MWh/h for the period of 4-9pm during any day between June 1 and October 31 except for event days. The Net Peak Demand Impacts value is the average MWh/h for the period of 7-9pm during any day between June 1 and October 31 except for event days.

6. Diagram of Program

This section is not applicable.

7. Evaluation, Measurement & Verification (EM&V)

No process evaluation or other evaluation effort will be undertaken to identify evaluation needs for this program. This program employs a robust embedded M&V strategy (as described in the program's Population-level NMEC M&V plan).

8. Normalized Metered Energy Consumption (NMEC)

The Peak Flex Market's Population-level NMEC M&V Plan is provided with this implementation plan and is integrated into the Peak Flex Market web page, found at https://www.aesc-inc.com/mce-peak-flex/.

MCE Peak Flex Market Program Manual

How the MCE Peak Flex Market Works

Any aggregator[7] who has signed the Participating Aggregator Agreement (PAA) is allowed to participate in MCE's Peak Flex Market program. The 2024 MCE Peak Flex Market Program Manual is an update for the summer 2024 event season which begins June 1 and ends October 31. The Peak Flex Market is a demand response program but aligns with many of the guiding principles for- population-level Normalized Metered Energy Consumption (NMEC) programs.

The MCE Peak Flex Market enrolls projects in a single-stage process. Participant information is collected from aggregators along with an estimated kW reduction and various permissions and acknowledgments to complete a formal enrollment. The summer 2024 program design is event only (solely event response). Demand response (DR) event days will mostly align with California Independent System Operator's (CAISO) Flex Alerts[8] and high day ahead market prices. MCE may also elect to call demand response events during forecasted energy supply shortfalls or weather-related emergencies, and for a limited number of test events during the summer period. The program will strive to notify participants via email within 24 hours of each event but does not guarantee event notification lead time[9]. Applications will be checked for eligibility and completion prior to official enrollment into the Peak Flex Market and can be subject to additional documentation and review.

The Peak Flex Market is agnostic to measures and business models, but, consistent with CPUC Decision (D.) 16-09-056, on-site generation of electricity via combustion of fossil fuels is prohibited. Additionally, aggregators must attest that the sites will not draw more from the grid to offset batter discharge.

Peak Flex Market incentive payments are paid based on performance of an aggregator's portfolio of projects and occur after the conclusion of the summer season.

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[7] Aggregators, or implementers, are participating vendors or program partners who generate energy efficiency and/or demand savings for an aggregated group of customers.

[8] https://www.flexalert.org/

[9] CAISO Flex Alert notifications can be issued with less than 24 hours' notice to the public and therefore the program will do its best to relay available information as soon as possible. For details on Flex Alert notification and system emergency protocols, see: http://www.caiso.com/Documents/4420.pdf

Event Triggers

The Peak Flex Market program will mostly call demand response events that align with CAISO's Flex Alert days as well as high day ahead market prices. Event length, number of hours in the event, may vary based on grid conditions but will mainly fall within peak hours (4pm - 9pm) and will typically last for 2 to 3 hours, starting and ending on the hour.10 The program anticipates calling a minimum of seven events over the course of the summer.

The program has the follow event triggers:

1. CAISO Flex Alerts: the program will call a DR event if CAISO issues a Flex Alert during any of the peak hours (4 – 9pm).

2. High Day Ahead Market Prices: The program will monitor CAISO Day Ahead Market (DAM), referencing the node: DLAP_PGAE-APND, to determine if an event should be called. An event may be called if at least two consecutive hours exceed $300. Each event will be a minimum of two hours. If only one hour exceeds $300, an event will not be called. If there are more than two hours above $300, all hours exceeding this price will be called, with a maximum of five hours. MCE may choose to change this threshold based on current summer conditions.

3. Other: MCE may also elect to call demand response events during forecasted energy supply shortfalls or weather-related emergencies, and for a limited number of test events during the summer period.

Aggregators' portfolios will be included in all events unless they notify the Program five or more hours in advance that their portfolio will not be participating. All portfolios that did not provide advance notification on non-participation will be measured, including any who may not have reduced usage during the event ("lack of performance"). Those portfolios that lack performance will negatively impact the Aggregator's total performance, as the increase in usage will be added to any decreases in previous events, resulting in a lower performance payment. Therefore, it is very important for Aggregators to provide the five-hour advance notification should they know their portfolio will not participate in a given event.

[10] MCE reserves the right to call events for longer periods outside of peak hours due to market conditions.

Eligibility Requirements

Aggregator Eligibility

Any organization that can meet the requirements as listed in the Participating Aggregator Agreement (PAA) can participate in the MCE Peak Flex Market. Aggregators are participating vendors or program partners who generate demand flexibility for an aggregated group of customers.

If an organization can meet these listed requirements, they must sign the PAA to officially submit and enroll projects.

Project and Customer Eligibility

In general, customer eligibility requirements include:

- Project site must be in MCE's service area[11] and receive electric generation from MCE[12];
- Sites must be enrolled prior to the Event to be eligible to participate.

For additional details on eligibility please see the Eligibility Criteria section of the M&V Plan.

MCE Direct Customer Enrollment Eligibility

The Peak Flex Market is also structured such that MCE can act as a project aggregator of select customers, prioritizing outreach to high-potential customers and passing down incentives to customers based directly on performance. Customers must meet the eligibility requirements above in addition to the following:

- Must be a non-residential customer receiving electric generation from MCE;
- Have a dedicated staff member able to influence energy usage at customer site(s);
- Be able to develop a plan of action to drive load impacts at customer site(s);

For MCE aggregated customers, MCE will verify customer eligibility and work directly with the AESC team to ensure that expected load reduction predictability is satisfactory. Customers who are unable to demonstrate peak period savings may be excluded from participation in the Direct Customer Enrollment opportunity. More information on eligibility can be found in the Eligibility Criteria section below.

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[11] https://mcecleanenergy.org/areas-we-serve/

[12] https://mcecleanenergy.org/understand-my-bill/

Project Enrollment Process

Enrollment

The Peak Flex Market will consist of a single event-only (demand response) enrollment pathway for aggregators in 2024. Event performance will be compensated at $2,000 /MWh. Only event hours will be measured and compensated.

Aggregators must include the following items at intake:

1. Contact information for their company;
2. Contact information for the customers being enrolled;
3. SAID
4. Energy reduction plan
    a. Expected load reduction (kW)
    b. Expected load reduction savings (%)
    c. Intervention strategies (HVAC, Lighting, Battery Energy Storage, Process Change, Other)
    d. Description of the interventions
5. Dual Enrollment details
6. Certification that customer agrees to enroll in the program, accepts all terms and conditions, and agrees to share usage and non-usage data for program purposes.

Upon completion of the project enrollment form, AESC will review and verify that the enrollment is complete. If the review is not passed, AESC will review the results with the Aggregator to resolve any issues identified.

AESC and MCE maintain the right to subject any application to additional review. All large customer sites (A19/B19/A20/B20) will be subject to a review at intake to which considers the expected percent reduction during events and peak CV(RMSE).

Bulk Enrollment

Aggregators enrolling multiple sites at once with an intervention will have the option to utilize a separate bulk enrollment pathway. These enrollments will require the standard project documentation. If standard documentation is not provided by an aggregator, the aggregator may submit alternative documentation for approval on a case-by-case basis to the program. Bulk enrollments will be uploaded using each customer's SAID. However, if an aggregator cannot provide customer SAIDs, they may contact the program to potentially submit addresses with no guarantee of matching to a customer. Bulk enrollments may also take eligibility risk with projects becoming ineligible after data screening. Aggregators will review the matched customer list and assume any risk from incorrect address mapping.

Incentive Payments

How Incentives are Calculated

For each portfolio participating in events, only event hours will be measured and compensated, with each event hour maintaining a value of $2,000/MWh. Interventions will be valued only during peak summer hours (4-9pm), June 1 through October 31 when an event is active.

Projects in an aggregator's portfolio become "active for payment" immediately upon enrollment. Further details on this process can be found in the "Payments and Incentives" section of the M&V plan.

Aggregator incentive payments will be made based on payable savings determinations using population-level NMEC methods described in the gross and net sections of the M&V plan. Payments for the program will be made annually after the close of the summer season, for active projects in the aggregator portfolio.

The yearly measurement period is:

- June 1 – October 31

Payments are expected to be made by December 31 of the program year. Incentives will be issued within 30 days from the date that AESC submits the payment recommendation to MCE. If there is an error in the payment recommendation requiring re-issuance from AESC, the payment timeline resets to 30 days from when the payment recommendation is re-submitted to MCE. Aggregators will be alerted if there's a deviation from this timeline.

Sites with Storage System Submeter Data

Projects submitted as a storage system will be paid and claimed based on device telemetry. Event days will be paid and claimed on the net of the hourly charging and the hourly discharge multiplied by the $2,000/MWh event price and compared to the baseline; for more details see Table 1, Peak Flex Analytical Methods Summary below.

Invoicing and Payment

Please see the Measurement & Verification Plan for the details of payment calculations, timelines, and non-routine event adjustments.

Audits

No pre-or post-on-site audits are required.

Sub-Program Quality Assurance Provisions

Quality Assurance Plan

This section is not applicable. See M&V plan for meter data quality control procedures.

MCE Peak Flex M&V Plan

Program Name: MCE Peak Flex Market
Program Administrator: MCE
Market Implementer: AESC
M&V Subcontractor: Demand Side Analytics

Summary

This is a Program-Level Measurement and Verification (M&V) Plan for the MCE Peak Flex Market program. For summer 2024, the Peak Flex program will focus exclusively on event-based peak demand reductions.

The availability of non-event days for Peak Flex participants creates a fundamental difference in the estimation procedures compared to MCE's Energy Efficiency Market programs. With EE, once the intervention is in place, it stays in place through the end of the useful life of the equipment. As a result, the CPUC NMEC Rulebook procedures are necessarily focused on pre-post analysis. The intermittent nature of the Peak Flex intervention triggered by demand response events (some days are events, but most are not) allows for a measurement approach which uses non-event days during the same summer season to estimate the counterfactual for a participant or group of participants. While the Peak Flex M&V approach is not population NMEC in its typical form, the methods are grounded in the guiding principles of population NMEC, namely:

- The calculation methodology should be transparent and replicable.
- The estimation procedures are fixed and documented up front and implemented consistently without site-specific judgements or adjustments.
- Aggregator compensation is based on the value of the reductions to the grid.

The program implementation plan for the Peak Flex Market program provides the details for how the program shall be implemented. Aggregators enroll sites and make a commitment to perform on event days. Demand response event days will mostly align with (CAISO) Flex Alerts[13] and high day ahead market prices.

MCE may also elect to call demand response events during forecasted energy supply

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[13] https://www.flexalert.org/

shortfalls or weather- related emergencies, and for a limited number of test events during the summer period. Refer to the "Events Trigger" section of Program Manual for more details. The program will strive to notify participants via email within 24 hours of each event but does not guarantee event notification lead time. Due to the 'day ahead' notification, the measurement approach will not apply a same-day adjustment to the counterfactual usage as participant loads could be affected by event preparations like pre-cooling or other load shifting into the pre-event period. Instead, a weather-sensitive adjustment will be applied for weather-sensitive customers to ensure the baseline is an accurate reflection of the participant's counterfactual usage.

Event start time and duration will vary based on grid conditions but will only fall between peak hours of 4pm and 9pm and are expected to last for 2 to 3 hours with a maximum duration of 5 hours. Compensation for all aggregators will be set at $2,000 per MWh where the delivered net MWh will be summed across all event hours in summer 2024.

A. Analytical Methods

This Peak Flex program is designed for all sectors (residential, commercial, industrial, agricultural) within MCE's service area. Qualified aggregators will mostly focus on control of a specific technology (i.e. thermostats, batteries, pumping) or industry type but the implementation plan does not limit eligibility to specific equipment or industry types.

Initial load reduction estimates and strategies will be reviewed and validated by the AESC team at enrollment. Estimates and forecasts should be grounded in past performance and/or qualified assessments of site and customer potential. Since aggregator payments are based on metered impacts, not calculated estimates, reviews are utilized to ensure estimates are reasonable and based on industry best practice. This review process will help ensure customers receive reliable estimates of savings potential and that MCE can have confidence in forecasted impacts and effectively manage performance payment budgets.

Following a review of intake materials and historic load data, participating sites will be placed into one of the three groups shown in Table 1. The eligibility criteria and performance calculations vary by group.

Table 1: Peak Flex Analytical Methods Summary

Methodological Element	Mass market customers	Large Customers with Predictable Schedules	Battery Storage
Distinguishing Characteristic	Default assignment for residential and non-residential accounts participating via an aggregator.	Accounts on rate A19/B19, A20/B20, or AG and AGF	Battery discharge is the sole mechanism for event reductions.
Analysis Technique	Simple difference-in-differences regression	10-in-10 Baseline (4/4 for events occurring on weekends or holidays) with option for Weather Sensitive Adjustment	10-in-10 baseline with no adjustment. 4/4 Baseline for events occurring on weekends or holidays. Aggregate for residential and site-level for commercial.
Data source	AMI data (whole building)	AMI data (whole building)	Battery end use
Control group	Yes, individually matched	No	No
Control Days	Yes. Non-event days with similar temperatures are included.	Prior 10 eligible days of last 45. Prior 4 eligible days of last 45 for events occurring on weekends or holidays.	Prior 10 eligible days of last 45. Prior 4 eligible days of last 45 for events occurring on weekends or holidays.
Adjustment	Net out of absolute kW differences between treatment and control observed during control days. This is accomplished automatically in the Difference-in-Difference (DiD) regression.	For weather-sensitive sites, a symmetric adjustment capped at ±20%. No adjustment for sites that are not weather-sensitive site.	No adjustment
Screening	Occurs at the aggregator level. Expected reduction of 10% relative to average 4-9pm summer load required in aggregate. Minimum	Case-by-case eligibility review at intake based on expected reduction and	Data quality. Compare AMI data to solar and battery data provided by the aggregator to

	number of sites will be reviewed at intake based on expected reduction and predictability of loads at participating sites.	peak load CVRMSE.	validate the timing and magnitude of Peak Flex response via battery discharge.
Reasoning for recommendation	Highly accurate Simple to explain and replicate Most common evaluation method	Sites are unique and often lack good comparison sites 10-in-10 baseline was recommend by 2017 CAISO baseline accuracy study[14] Large sites are highly influential and thus need to be predictable	Using battery end use data avoids the noise from other end uses and solar Recommended method based on battery storage settlement accuracy study

The bullets below define and elaborate on several key concepts.

- **Weather Sensitive Adjustment (WSA)[15]:** a slope (delta kW per degree F). Based on summer 2023 weekday loads 4-9pm. This adjustment is used to calibrate participant baselines to reflect differences in weather between baseline and event days.
- **Peak load CVRMSE**: CVRMSE is the Coefficient of Variation of the Root Mean Square Error and is a measure of how predictable the loads of large customers are. Site screening for large customers will be done ahead of accepting that site's enrollment.
- **Matched controls**: Non-participating MCE customers who use electricity similarly to the participating consumers are selected to be selected to be the control group for mass market customers.
- **Level of aggregation:** aggregation occurs at different levels for each group:
    - For the mass market customers, the average treatment effect for each site is calculated at the aggregator portfolio/event/hour. Those treatment effects are then multiplied by the number of sites active in each hour to get the portfolio level savings for each hour, and the total savings are derived from the summation of those savings across the whole summer. Baselines can be calculated, but are not necessary, since the treatment effect is calculated directly. Site level savings are not calculated.

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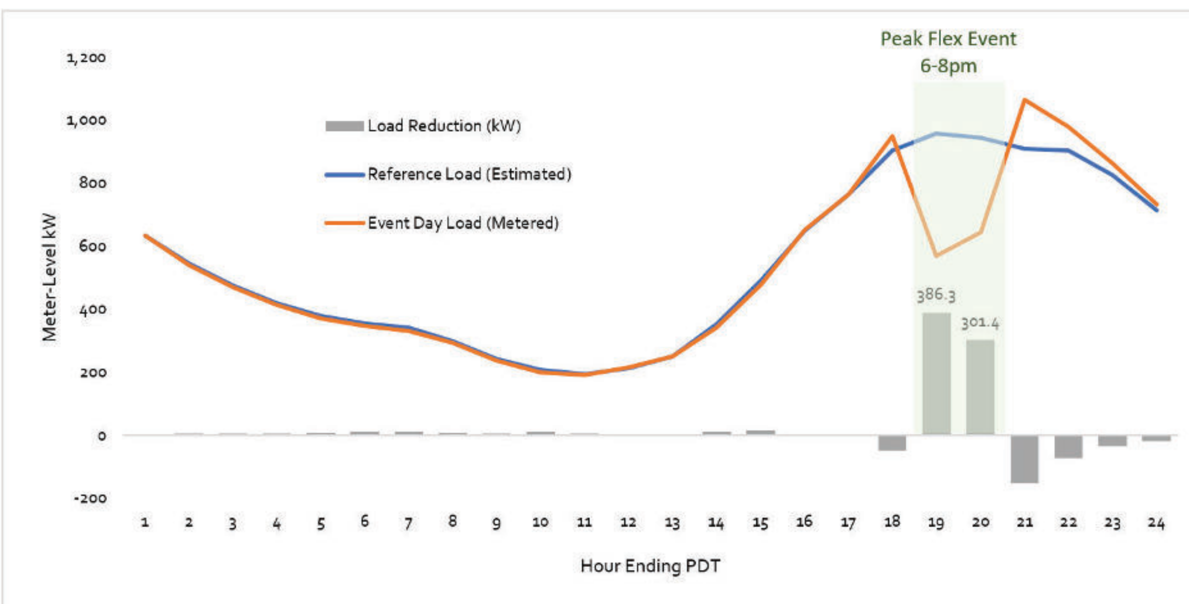
[14] https://www.caiso.com/Documents/2017BaselineAccuracyWorkGroupFinalProposalNexant.pdf
[15] More information can be found here.

- For large customers, site level baselines and savings are calculated using an adjusted 10-in-10 methodology. The aggregate baseline and aggregate savings are calculated by summing across all sites and hours.
- For residential battery customers, hourly battery discharge net of any battery charging energy data is aggregated at the portfolio level before the unadjusted 10-in-10 calculations, so aggregate baselines and savings are calculated directly. Site level savings are not provided, but the 10-in-10 calculation could be easily reproduced on the site level by aggregators themselves if they wish.
- For commercial battery customers, 10-in-10 calculations are done at the site level for hourly battery discharge net of any battery charging energy data. The aggregate baseline and aggregate savings are calculated by summing across all sites and hours. Aggregators will be paid on these aggregate savings. Data on site level savings will be made available.

Payable Savings

Payable savings constitute the basis of payments between the Program Administrator and aggregator(s). **Error! Reference source not found.** shows the general procedure. For each hour of each event day, the AESC team will estimate the reference load. The reference load, also referred to as the baseline or counterfactual, is an estimate of what the electric demand of the site, or portfolio of sites, would have been absent Peak Flex dispatch. Peak Flex reductions are simply the difference between the reference load and observed load on the event day.

Figure 1: Peak Flex Savings Illustration



The performance of the hypothetical site shown in **Error! Reference source not found.** is 687.7 kWh over the two-hour event window. Aggregator compensation for 687.7 kWh of reduction is $1,375.40 based on the incentive level of $2,000 per MWh. While the M&V approach quantifies impacts in all 24 hours of the event day, increases or decreases in load during the hours prior to or after the event have no impact on the payable savings or compensation. The hypothetical site shown in **Error! Reference source not found.** would be held harmless for any pre-cooling or pre-pumping activity in the hours leading up the event or any energy recovery during the hours following the event.

Invariably, some participating sites will have an observed load greater than their reference for an event hour due to noise in the estimation. The payable savings procedure seeks to balance fairness to aggregators while limiting MCE's exposure to paying for asymmetric handling of noise.

A wide range of building types may be part of the program and a threshold baseline model fit will be a precursor for project acceptance. Peak Flex payable savings for event-based performance will not be adjusted for free ridership. Payable savings will be based on the following computations:

1. Compute hourly reductions.
2. Hourly reductions (both positive and negative) from each participating site are totaled across all summer event hours. For mass market customers, the treatment effect is multiplied by the number of customer hours. For commercial battery and large customers, each individual reduction is summed across hours and customers. For residential battery customers (where the savings are already aggregated across customers), the savings only need to be aggregated across hours.
3. Summer 2024 MWh totals from step #2 are summed for each aggregator portfolio.
4. Across the summer season, if the result of step #3 is negative for an aggregator portfolio, their payable savings are set to zero.
5. Each aggregator's portfolio payable savings (MWh) is multiplied by $2,000 MWh to compute compensation.

Claimable Savings

MCE does not plan to claim savings to the CPUC from the 2024 Peak Flex program.

B. Calculation of Load Impacts

Data Requirements

The Peak Flex program relies on data-driven measurement and verification, so acquisition and data preparation are an important precursor to the calculation procedure. Core data streams include:

- **Program participation information**. Basic information about each enrolled service account including the enrollment date, service location, electric tariff, NEM status, DER interconnection details, and information on dual enrollment in other DR programs if approval for dual enrollment is granted.

- **Hourly meter data from MCE for participants and non-participants**. For each hour of summer 2024 the kWh delivered, and kWh received (for NEM customers). All calculations will rely on net load (delivered minus received).

- **Hourly weather data from CALMAC**. Weather data from the nearest weather station will be merged with hourly load data based on service zip code.

The unit of settlement will be with each aggregator portfolio. As an aggregator may have multiple portfolios, each will have its own settlement. DSA can supply commercial battery and large customer aggregators with customer level savings data but cannot do the same for the mass market and residential battery customers.

Rules consistent across all three types of customers

Dual Enrollment

MCE/AESC will notify aggregators of Peak Flex events either the day prior or day of the event. If an aggregator indicates at intake that their portfolio is dually enrolled in another DR program (e.g. DSGS) and that program dispatches on the PF event day, the aggregator’s portfolio is omitted from the performance calculations. Dual Enrolled days are excluded from baseline calculations for any other Peak Flex event. Each aggregator should split up their customers into dual enrolled and non-dual enrolled portfolios, so they can call one and not the other.

Opt-outs

Each Aggregator can opt-out their entire portfolio of an event, given they communicate this to MCE/AESC at least 5 hours before the event. If an aggregator alerts MCE/AESC prior to the Peak Flex event start time that they intend to opt-out of the event, the aggregator's entire portfolio is omitted from the performance calculations for that event. Portfolios that are not identified as dually enrolled portfolios at the beginning of the season must participate in at least 50% of demand response events in the season and compensation will be at MCE's discretion. No such minimum threshold applies to portfolios that are dually enrolled. Opt-out event days are eligible to be used as non-event days for M&V. Opt-outs must include the entire portfolio, and not just individual customers or sites.

Eligible days

All days are eligible, including weekends and holidays. Both the Large Customer and Battery baselines have provisions to only use like days (weekdays with weekdays, weekends and holidays with weekends and holidays) when constructing the baseline. Proxy days used in the mass market difference in differences will also be selected from similar day types.

Mass Market Customers (Matched Controls with Difference in Differences (DiD))

Mass Market Customers will have a difference in difference panel regression using matched controls computed. The measurement will be calculated using the following procedure:

Proxy Days

Not all days are used as baseline days. Each event day will have three proxy days used as control. The proxy days are chosen from all other non-event and non-dual enrolled event days in summer 2024 that have the same day type as the event (IE weekday or weekend/federal holiday). From those, the three days within the prior 45 whose system load is closest to the event system load during the hours of 4pm to 9pm are chosen as the three proxy days.

For each aggregator portfolio / event day, the following regression is run:

$$kWh_{t,i} = \sum_{j=first\ hour\ of\ event}^{last\ hour\ of\ event} \beta_j \cdot D_{i,j=t} + h_t + d_t + c_i + \varepsilon_{t,i} \tag{1}$$

- $kWh_{t,i}$ is the demand for customer *i* at hour *t*
- $D_{i,j=t}$ is an indicator of customer *i* being in the treatment group and hour *t* being an event hour
- $h_t,\ d_t,\ c_i$ are hour, date, and customer fixed effects

- $\varepsilon_{t,i}$ is the error term, clustered on customers

- β_j is the treatment effect of the event

While this is completed via a panel fixed effects regression, because there are no continuous variables, the treatment effects could be calculated by demeaning the data on the fixed effects values and then calculating the difference in the difference of means.

Aggregating treatment effects

β_j is multiplied by the number of enrolled sites for that event day. That number, the estimated effect of the event on the load for the entire aggregator portfolio for hour j, can then be added to the observed hourly load for the treatment group to get a baseline load. The total load impact from the summer is the summation of these estimated effects. This is the number that aggregators are paid on.

Individual level impacts

This regression does not return individual customer level savings.

Control Group Construction

A matched control group is constructed using a statistical procedure that ensures the control group is representative of the population of program participants. The matches are made using the following rules:

- Participants are assessed on basic characteristics such as (but not limited to) climate zone, tariff, interconnection information, industry and size. These characteristics will define a participant's segment. Controls for each participant will be selected from the same segment via stratified random sampling of eligible non-participants in MCE's service area.

- AMI data for participants and the sampled non-participants will be requested and additional meter-based features will be computed. These features may include weather sensitivity, percent of consumption on peak, maximum demand in the peak and net peak periods, or other measures of typical consumption patterns.

- Participants will be matched within relevant strata that have meaningfully distinct patterns of energy use. For example, customers with on-site solar will be matched only with others of similar solar system sizes. Other segmentation strata may include climate zone, weather sensitivity, and industry (for non-residential participants). The unique combination of these characteristics become the participant's segment in which they will be matched with a control.

- Matching is done within the aforementioned segments via Euclidian distance matching on relevant electricity consumption features. Matches will be evaluated on the basis of their goodness-of-fit across the average proxy day, with weights specifically in the 4pm-9pm window. Non-participants customers may be matched multiple times to different participant accounts.

- Candidate non-participants will have no changes in NEM status or EE during the Peak Flex season.

Large Customers (10-in-10 Baseline with Weather Sensitivity Adjustment (WSA))

Large customers are more heterogeneous and are not likely to have sufficient similar non-participants to act as a comparison group. Instead, a within-subjects approach is used where the reference load on non-event days is computed via a customer baseline (CBL).

Qualifying for the program

All large customers are eligible, provided their Coefficient of Variation of the Root Mean Square Error is reasonable. The CVRMSE is calculated using whole-building peak-period AMI data from the summer of 2023. If the CVRMSE for a site is large (approximately ≥ .5), additional review of the site will be done. Eligibility for highly variable sites will be considered on the basis of the size of the reduction, the site's peak period typical load and the end use being curtailed. The CVRMSE is calculated in the following manner:

- The seven days in summer 2023 with the highest system loads between 4pm and 9pm are declared "proxy event days"

- For all hours t between 4pm and 9pm on proxy event days, an adjusted consumer baseline CBL_t^{adj} is calculated using the 10 in 10 procedure described in the rest of this section. The CVRMSE is then calculated by comparing the realized demand kWh_t for those hours:

$$CVRMSE = \frac{1}{\overline{kWh}} \sqrt{\frac{\sum_{t=1}^{N} \left(kWh_t - CBL_t^{adj}\right)^2}{N}} \tag{2}$$

Calculating the unadjusted baseline

The unadjusted baseline for each hour of the treatment day is the average demand in that hour from the past 10 qualifying days, if the event day is a weekday. If the event day takes place on a weekend or federal holiday, only use the past 4 weekend and holiday days. Qualifying baseline days are non-event days and non-dual enrolled event days for resources that have dual dispatch. Days that are more than 45 days in the past from the event day do not qualify.

WSA adjustment

Weather sensitive sites will have their baseline calibrated via a weather-sensitivity adjustment (WSA). The WSA accounts for the reality that events tend to be called on hot days while baseline days are necessarily called on non-event days that may have a different (cooler) temperature profile. This adjustment is capped at 20%, meaning that the baseline cannot be scaled higher than a factor of 120% of the original value or lower than 80% of the original value. To compute the WSA, the following procedure is run:

First, run an OLS regression on summer 2023 loads from 4-9pm for each individual site, excluding any days for which the participant had a demand response event or outage:

$$kWh_t = \beta_{WSA} \cdot Temp_t + h_t + w_t + \varepsilon_t \tag{3}$$

- kW_t is the demand at time t
- $Temp_t$ is the outside temperature in Fahrenheit (continuous variable)
- h_t is an hour fixed effect, w_t is a weekend fixed effect, and ε_t is the error term
- β_{WSA} is the WSA for the site being examined.

If β_{WSA} is positive and the p-value is less than 0.05, the site is declared weather sensitive. For sites declared to be weather sensitive, the 10-in-10 baseline is adjusted in the following manner (no further adjustment is necessary for sites that are not weather sensitive):

$$CBL_t^{adj} = \begin{cases} CBL_t + \beta_{WSA}(\Delta Temp_{eventhours}) & if \ \dfrac{|\beta_{WSA}(\Delta Temp_{eventhours})|}{CBL_t} \leq 0.2 \\ CBL_t\left(1 + 0.2 \cdot \dfrac{|\beta_{WSA}|}{\beta_{WSA}}\right) & if \ \dfrac{|\beta_{WSA}(\Delta Temp_{eventhours})|}{CBL_t} > 0.2 \end{cases} \tag{4}$$

- CBL_t is the unadjusted customer baseline at time t for the site calculated from the 10-in-10
- $\Delta Temp_{eventhours_t}$ is the difference in temperature during event hours between the event day and the average temperature during event hours on all of the baseline days.

- CBL_t^{adj} is the customer baseline at time t adjusted for WSA
- The condition ensures that the adjustment is no larger than 20%
- $\frac{|\beta_{WSA}|}{\beta_{WSA}}$ is 1 if β_{WSA} is positive and -1 if β_{WSA} is negative, ensuring that the 20% adjustment goes in the right direction

Example: β_{WSA} = 11. Baseline average temperature is $Temp_{\square}^{10in10}$ = 86 and event temp is $Temp_{\square} = 89$, and $CBL_{19} = 200$. We adjust the consumer baseline up 33 kW to CBL_t^{adj} = 233. If CBL_{19} = 100, we would have only adjusted the consumer baseline up to $CBL_t^{adj} = 120$ since in that case the adjustment would have been greater than 20%.

Aggregation of Savings

Each site's estimated savings from the policy is the difference in the adjusted baseline from the observed demand. Those savings are summed up across all event hours, events, and sites to calculate the aggregate season-wide load impact for each aggregator portfolio. If that aggregate impact is negative (indicating savings), the aggregator is paid on this number.

Battery Storage

For batteries, the dependent variable is net energy through the battery inverter. On non-event days, battery storage sites are assumed to operate their batteries normally. This may involve charging from on-site solar panels, charging from the grid, discharging the battery to meet gross load, discharging the battery to the grid, or leaving the battery idle. On Peak Flex event days, participants are expected to discharge their batteries at a higher rate in order to reduce grid constraint. This could mean covering a larger share of gross load or exporting stored onto the grid. If a Peak Flex participant charges their battery during an event, that would contradict the intent of the program and count against their performance.

Qualifying for the program

All battery customers are eligible, provided they are not dually enrolled in the mass market category of the Flex Power program, and that they pass a data quality check. This check compares the average whole building grid demand reported by the battery aggregator to the whole building grid demand from the AMI data. If there is a greater than 2% difference, the data quality check fails, then this site will go through the large customer group.

Aggregation

For commercial battery sites, the 10-in-10 baseline is calculated at the site level, without adjustments, and savings are calculated on the hour/site level.

For residential customers, battery sites are aggregated before the 10-in-10 baseline is calculated. For each hour in the summer of 2024, net energy is summed across every battery site in the aggregator portfolio.

Calculating the baseline

The baseline for each hour of the event day is the average in net energy through the inverter in that hour from the past 10 qualifying days if the event day is weekday. If the event day takes place on a weekend or federal holiday, we only use the past 4 weekend and holiday days. Qualifying baseline days are non-event days and non-dual enrolled event days. Days that are more than 45 days in the past from the event day do not qualify to be used in the baseline calculation.

Adjustments

There are no adjustments.

Aggregation of Savings

Each portfolio's estimated savings from the policy is the difference in the baseline net energy from the observed net energy. Those savings are summed up across event hours and events in the case of residential customers, and across sites, event hours, and events in the case of commercial customers to calculate the aggregate season-wide load impact for each portfolio. For residential customers, individual site savings within each portfolio will not be provided to the aggregator.

Interpolation of Missing Data

If MCE is unable to provide meter data for a Peak Flex participant during a Peak Flex event hour, the AESC team will be unable to estimate their performance. Since this negatively impacts an aggregator's compensation through no fault of their own, performance during hours with missing meter data will be set equal to sites average performance during Peak Flex events for which the site was active during the summer season for battery and large customers. For mass market customers, those hours will be omitted from the regression, but not from the number of sites used to multiply the treatment effect. Like utility meters, weather stations occasionally miss readings. However, the CALMAC weather data has robust interpolation procedures that ensure each station has a complete panel of weather records for use in modeling. Battery data must be available for M&V for at least 10 business days prior to a Peak Flex event. For any sites where data is not provided for at least 10 business days, that site will be excluded from the portfolio's settlement. More information on how battery projects are evaluated can be found in the Methods, Payments, and Risks section of this M&V

Plan.

Adjusted Gross and Net Savings

Comparison groups used in meter-based programs have the unique challenge of needing to quantify impacts during implementation as well as address dissimilar responses to exogenous factors, unpredictable exogenous events, and limited data for assigning buildings to cohorts. Program influence in a demand response program is more apparent, however. If MCE elects to report net savings associated with this program, a Net to Gross Ratio (NtG Ratio) of 1 will be used.

For sites participating in other demand response programs, adjustments may be made in accordance with the "Demand Response Disaggregation" section. All adjustments will be reflected in the payable savings to aggregators.

Participation in Energy Efficiency Programs or Change in NEM Status

Since energy efficiency and solar impacts are in place every day and the Peak Flex program is activated on specific days, there is limited threat of biased estimates due to EE participation or the presence of solar. The exception occurs when a site installs a new EE measure or changes their solar status mid-summer. For mass-market customers, solar segmentation will be assigned for participants and matched controls based on their solar status during the majority of events in 2024. The number of switchovers should be about the same in both control and treatment groups (given a large enough sample size), which will control for any bias introduced from solar installations. Due to the nature of a within-subject M&V method, no compensation will be calculated for events that occur within 30 days of a new solar or EE installation.

MCE Marketplace Demand Response Disaggregation

During Peak Flex event days, DR impacts are the primary intervention of interest. Sites that enroll in both Peak Flex and the Efficiency Market programs require special attention. The AESC team will omit Peak Flex event days from the baseline and performance calculations for the EE Market programs for these customers. This prevents the Peak Flex response from biasing the EE measurement. The mechanics of the TSB calculation for EE works ensures that aggregators are still paid for the full value of their EE projects because the modeled savings are cast across the full EUL of the project with 365 (or 366 days) of avoided cost per year.

Participation in Other Demand Response Programs or Services

An aggregator may enroll sites in Peak Flex and a separate DR program or service at the same time, but simultaneous participation in two different programs and/or services during the same event period is disallowed. In other words, event days from separate DR programs and services will be blacked out from Peak Flex M&V and payments.

To be able to black out participation in the Peak Flex during times where sites participate in other DR programs or services, the aggregators must provide the following information. If the aggregators cannot provide this information, dual enrollment under Peak Flex and another DR program or service will not be allowed.

1. The aggregator must disclose any separate DR program participation or services during enrollment for each site (specifying which specific DR program or service the customer site is enrolled in).
2. Participation in the Peak Flex Market program does not hinder or violate obligations to deliver DR resources in other services (programs, CAISO markets, contracts, etc.).
3. The aggregator provides participating event data (specifically, site and event days) for other DR programs and services and in the specified format for each site and within 15 days following the end of the previous month. If no events have occurred, the Peak Flex Market Aggregator must still submit the same event data template, confirming that there have been no events.
4. The aggregator attests to the accuracy and completeness of the submitted event data. The event data may be audited in the future.
5. The aggregator completes the onboarding process for event data submittal, demonstrating ability to provide the Peak Flex Market program with event data required in the specified format. This must be completed before any sites are enrolled.

C. Data Security and Data Collection

Data Security

Data security and customer privacy are paramount for the program and MCE.

The AESC team has implemented rigorous data security procedures and protocols at every step of data transfer, analysis, and reporting for handling AMI data and customer information.

Data Collection

Variables Needed:

- Hourly AMI data for summer of 2023 and summer of 2024.
- Hourly solar and battery storage data from battery aggregators (battery clients only). Aggregators will be responsible for providing battery data at the end of the summer.
- Climate Zone, Tariff, annual kWh, NAICS code, if applicable.

- Zip code (in order to get the nearest CALMAC site).
- Solar status and date of install.

The availability and quality of hourly consumption data for proper baselines is fundamental to identifying and qualifying program participants. Aggregators will collect the site and meter information required for full customer identification in MCE's CRM system. For developing a comparison group, a sample of non-participant customers will be identified to perform accurate matching and comprise a reliable comparison group. Data must be delivered in a clean readable format. Any duplicated data will be thrown out. Any overlaps in meter datasets will resolve to the dataset with the largest time period.

D. Monitoring and Documentation QA/QC Over Reporting Period

The AESC team will maintain quality data management and monitoring throughout the program life to ensure the performance estimates and aggregator compensation are auditable and reliable. The AESC team will provide a fully auditable and verifiable record to track each meter that is modeled and its fate over the course of the program.

E. M&V Related Plans for Project Types, Design, Payments, Measures and Cost Effectiveness

Targeting

Recruiting customers based on insights from AMI data analytics can effectively identify sites with flexible loads during times of grid constraint. These analyses may be conducted by AESC in partnership with qualified aggregators to find populations that may have desirable load characteristics during the 4-9 pm summer window when Peak Flex events will be called. Desirable load characteristic include magnitude, predictability, weather-sensitivity, and share of daily load within the net peak.

Program Design Criteria and Uncertainty

Program Design Criteria

Four main factors affect the ability to accurately detect savings.

1) **The effect or signal size** –Large changes are easier to detect than small ones. The effect size is understood as the percent change.

2) **Inherent data volatility** – The more volatile the load, the more difficult it is to detect small changes. It is more difficult to estimate savings with precision when a handful of very large customers drive the results.

3) **The ability to filter out noise or control for volatility** – At a fundamental level, statistical models, baseline techniques, and control groups – no matter how simple or complex – are tools to filter out noise.

4) **Sample/population size** – It is easier to precisely estimate average impacts for a large population than for a small population.

The program has a degree of control over each of these factors. Sites with small expected reductions or unpredictable load patterns can be rejected if they are large enough to pose significant risk to program goals and economics. Outreach efforts can also be focused on aggregators with the reach to bring in a large portfolio of sites.

The benefits of aggregation are one of the most pervasive findings of DSM evaluations.[16] Estimating performance at the aggregator level except in the case of large unique sites limits the noise in estimates. Aggregation of hourly event impacts across the entire season also limits risks of payment asymmetry.

Uncertainty

The margin of error at the 90% confidence interval will be reported for each aggregator's mass market portfolio. No confidence intervals can be reported from the 10-in-10 methods employed for the large customer and battery customer groups.

Payments and Incentives

Aggregators will be eligible for an incentive payment depending on the performance of their portfolio. There are no predetermined customer payments or rebates set by the program - participant incentives are determined by participating aggregators, and are expected to be variable depending on business models, cost of service, etc. Aggregators will be required to report any incentive payments passed on to the customer. The $2,000/MWh "Event Price" payment is designed to pay directly on the value of measured performance during event hours. Estimated savings (positive or negative) outside of event hours will not be compensated or otherwise affect an aggregator's portfolio.

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16 See Table 7 of https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/emergency-load-reduction-program/statewide_a6_elrp_baseline_evaluation_report_01172023.pdf for a useful summary

MCE payments for the program will be made based on payable savings determinations using the methods described in this M&V plan. Payments for the program will be made in Q4 once the data transfer and measurement is complete.

AESC will document in an electronic, revenue-grade, auditable incentive tracker the recommended payments to support aggregator invoices to MCE after each Peak Flex summer event season. Invoice payment recommendations will be based on payable savings results.

Qualifying Measures

The Peak Flex program is technology agnostic. Any behavioral or technical strategy that reduces demand for electricity during Peak Flex events is eligible, except fossil fuel back-up generation. Aggregators must attest that their Peak Flex load impacts are not due to behind-the-meter fossil fuel generation of electricity to offset their consumption from the grid.

Cost Effectiveness

There are no cost effectiveness requirements for the Peak Flex Market program.

F. Eligibility Criteria

Peak Flex specific eligibility criteria include:

- Large commercial customers must be screened using site CVRMSE thresholds during their peak hours. Sites with CVRMSE > 0.5 will be admitted on a case by case basis.
- Industrial and Agg sites are eligible for Peak Flex provided that these sites commit to a minimum savings threshold > 15% across event periods. Sites must be enrolled prior to the Event to be eligible to participate.
- Sites may be omitted from settlement for a given event due to a change in solar or EE status within a month of the Peak Flex event day or due to insufficient data to calculate the baseline
- Battery Energy Storage system projects do not have to abide by data sufficiency or model fit requirements listed above. They will be determined as eligible under the following conditions:
    - Residential (single-family and multifamily) or non-residential customer;
    - Project site must be located in MCE's service area and receive electric generation from MCE;
    - Sites must be enrolled by no later than September 1, 2024; and
    - If already participating in another DR program, sites cannot be dual enrolled unless the aggregator commits to providing event data from the additional program (see "Participation in Other DR Programs" in the M&V Plan).
    - Battery data must be available for M&V for at least 10 business days prior to

a Peak Flex event. For any sites where data is not provided for at least 10 business days, that site will be excluded from the portfolio's settlement.

Aggregators will verify with customers that they do not plan to install major new load additions or subtractions, solar PV, or EV charging in the summer Peak Flex season. In addition, AESC will monitor sites for participation in the energy efficiency programs or interconnection changes during the summer event season. If sites are dual enrolled in another demand response program, event data must be provided as outlined in the "Participation in other Demand Response Programs" Section.

Customer sites with changes in solar status between June 1, 2024 and October 31, 2024 will be reviewed at the end of the season to determine if there are adequate non-event days with the same solar status to measure performance for each event day. Solar submeter data will not be accepted or incorporated into the performance calculations.

For participants relying exclusively on battery discharge to deliver Peak Flex load impacts, the program will accept battery inverter data as a means of valuation, provided certain minimum criteria are met, including but not exclusive to:

a. Aggregator must provide submeter data from the battery system in the template provided by the program within 45 days after the first enrolled Peak Flex event.
b. Aggregator must provide submeter data from the battery system for non-event days as well as event days beginning two weeks prior to the first Peak Flex event day of the season.
c. The Peak Flex Aggregator completes the onboarding process for submeter data submittal, demonstrating ability to provide the Peak Flex program with submeter data required in the specified format. This must be completed at intake.

More information on how battery projects are evaluated can be found in the Methods, Payments, and Risks section of this M&V Plan. Aggregators enrolling battery-only sites will only be eligible for payment following receipt of final inverter data in the specified format.

On-site electricity generation is not eligible for incentives from the Peak Flex program.

G. Effective Useful Life (EUL)

The Peak Flex market is event-based so the concept of EUL does not apply. Performance is measured for each event day and assumed to exist on the days that MCE dispatches participating aggregators.

H. Methods, Payment Terms, and Risk

Methods for Payable and Claimable Savings

Projects submitted as a storage system for load shifting will be paid and claimed based on device telemetry, which is the net of the hourly charging cost and the hourly discharge avoided cost minus market management fees. Event days will be paid and claimed on the net of the hourly charging and the hourly discharge multiplied by the $2,000/MWh event price. The Peak Flex incentive of $2,000 per MWh is the same whether the discharge serves gross load and exports back to the grid. Aggregators and participants should consider implications of the Peak Flex response on retail billing determinants.

Payment Terms

MCE will pay aggregators for their measured performance according to the terms of the participation agreement. Payments are expected to be made by December 31. Incentives will be issued within 30 days from the date that AESC submits the payment recommendation to MCE. If there is an error in the payment recommendation requiring re-issuance from AESC, the payment timeline resets to 30 days from when the payment recommendation is re-submitted to MCE.

Risk Mitigation

The Peak Flex Market program is a pay-for-performance design. One hundred percent of the payment to the aggregator is based on the estimated performance of their portfolio during Peak Flex events. The aggregator takes on the upfront risk along with the participants they enroll. Although the compensation structure is pay-for-performance, the Peak Flex program is not without risk to MCE, its ratepayers, and the AESC team.

- **Fixed costs and variable benefits**. While aggregator incentives are variable, there are certain fixed costs associated with running the program. If the performance of the program is poor, the fixed costs relative to benefits could strain the economics of the program.

- **Flat incentive rate**. The $2,000 per MWh incentive rate is a clear signal to the market but does not necessarily the benefit to MCE and its ratepayers per MWh of load reduction. The ratio of MCE's marginal costs to the incentive rate will likely vary from event hour to event hour. MCE's realization of reduced capacity obligations will also affect the value proposition.

- **Payment asymmetry.** While the M&V plan and settlement structure are structured to limit this risk, aggregators cannot be penalized for negative reductions. The extreme example of this a program with two aggregators that each deliver 1 MWh of load reduction. Due to noise in the estimation of impacts, one aggregator's performance is estimated at 11 MWh for a payment of $22,000. The other aggregator's performance is estimated at -9 MWh for a payment of $0. The net reduction of this hypothetical program is 2 MWh at a cost of $22,000. Despite an unbiased measurement approach that is accurate in aggregate, MCE acquisition cost per MWh is five times the expected rate.

The outreach and intake strategy seeks to minimize these risks to MCE and ratepayers by recommending a minimum load reduction percentage, rejecting sites with erratic loads, and settling at the highest level of aggregation possible – by aggregator at the end of the season.

The Peak Flex Market program will further mitigate risk of settlement dispute by using a consistent, transparent means of tracking the impacts for settling payable savings as described in this M&V plan. Payment to the aggregator is completely based on savings delivered at the meter and will be made at the end of the season. AESC will provide targeting support to the qualified aggregators in support of achieving their collective goals.

The Peak Flex Market is designed to limit risk to program administrators, moderate risk for aggregators via settlement at the portfolio level and minimize the interest in the savings from the entity calculating the savings.

I. To Code Savings Compliance

The goal of the Peak Flex program is event-based response with existing equipment rather than ongoing savings from equipment retrofit, so to-code considerations do not apply.

J. Bid M&V Plan

The Peak Flex Market program will not conduct a bidding process for this program. It will utilize an aggregator qualification approach that reduces barriers to entry. Bid M&V plans will not exist.

ATTACHMENT A. Tools, Methods, Analytical Approaches and Software Criteria

While Peak Flex is not a population NMEC program, the NMEC Rulebook outlines a useful set of criteria for the approaches and calculation software for M&V. **Error! Reference source not found.** itemizes the criteria in the left hand column and how the proposed tools, methods, analytical approaches, and calculation software in this M&V plan meet these criteria.

Table 2: Tools and Methods Summary

Tools, Methods, Analytical Approaches and Calculation Software	Compliance demonstrated in this M&V plan
Savings Calculations: *All analytical methods, including tools, algorithms and software used in savings and incentive or compensation payment calculations, must be made available to Commission staff and its consultants upon request.*	Analysis for this program will be completed in a statistical programming language such as R, Python or Stata.
Measurement Period: *Savings determinations must be made by comparing at least 12 months of post-intervention energy consumption to at least 12 months of pre-intervention energy consumption.*	This requirement does not apply for an event-based program. Nevertheless, the principle of comparing usage during unperturbed periods to the curtailed period is a key component of all three M&V approaches laid out in this M&V plan.
Transparency: *Data, methods and calculations must be made available to the PAs well as the Commission and its impact evaluators.*	The data requirements and approach are documents in this M&V plan. Code may be made available upon request.
Documentation and Replicability*: The methods used to calculate savings for NMEC programs must be documented in the program-level M&V Plan sufficiently such that savings calculations are able to be replicated by the PAs as well as the Commission and its impact evaluators. Upon request, the underlying participant consumption data and other data inputs must be made available to the PAs well as the Commission and its impact evaluators such that savings calculations can be replicated to reach the same result.*	The data requirements and approach are documents in this M&V plan. Code may be made available upon request.
Consistent, Pre-Set Method*: For Population-level NMEC programs, the specific measurement*	The data requirements and approach are documents in this M&V plan. Code may be

method(s) and calculation software must be determined before the program begins and applied uniformly to all sites in the program.	made available upon request.

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T

Albion Power Company
Alta Power Group, LLC

Anderson & Poole
Atlas ReFuel BART

BART
Buchalter
Barkovich & Yap, Inc.
Braun Blaising Smith Wynne, P.C.

California Community Choice Association
California Cotton Ginners & Growers Association
California Energy Commission
California Hub for Energy Efficiency
California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine
Cameron-Daniel, P.C.
Casner, Steve
Center for Biological Diversity
Chevron Pipeline and Power
City of Palo Alto
City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Communities Association (WMA)

Davis Wright Tremaine LLP

Day Carter Murphy
Dept of General Services
Douglass & Liddell
Downey Brand LLP
Dish Wireless L.L.C.

East Bay Community Energy

Ellison Schneider & Harris LLP
Electrical Power Systems, Inc.
Fresno
Engie North America
Engineers and Scientists of California

GenOn Energy, Inc.
Green Power Institute

Hanna & Morton LLP

ICF consulting

iCommLaw

International Power Technology
Intertie

Intestate Gas Services, Inc.

Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP

Leviton Manufacturing Co., Inc.
Los Angeles County Integrated
Waste Management Task Force

MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McClintock IP
McKenzie & Associates
Modesto Irrigation District

NOSSAMAN LLP
NRG Solar

OnGrid Solar

Pacific Gas and Electric Company
Peninsula Clean Energy
Pioneer Community Energy

Public Advocates Office
Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
Resource Innovations
Rockpoint Gas Storage

San Diego Gas & Electric Company
SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company

Spark Energy

Sun Light & Power
Sunshine Design
Stoel Rives LLP

Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.
TransCanada

Utility Cost Management
Utility Power Solutions

Water and Energy Consulting
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)

Yep Energy

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S PROPOSALS ON TRACK 3

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January 17, 2025

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    - Is an administratively simple way to increase transactability under SOD;
    - Will promote affordability without compromising reliability;
    - Maintains LSEs' responsibility to meet RA requirements;
    - Can improve the ability to meet RA requirements under the SOD framework, as can be demonstrated in analyses of 2025 YARA showings; and
    - Can be easily incorporated into the existing SOD showing template.
- The Commission should address co-located resources and RA needs, including:
    - Formalizing in the Track 3 Decision the determination made during Energy Division Staff office hours regarding allowing PCDS or FCDS co-located generation to count for storage charging sufficiency requirements or RA requirements for on-site or off-site storage; and
    - Reevaluating accounting methodologies to allow EO co-located resources to count as RA under the SOD framework when such resources are limited to the deliverable MW at the POI.
- The Commission should incorporate the local RA CPE data request process into the existing RA filing process.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S PROPOSALS ON TRACK 3

California Community Choice Association[1] (CalCCA) submits these proposals pursuant to the *Assigned Commissioner's Amended Scoping Memo and Ruling*[2] (Scoping Ruling)*,* dated November 1, 2024. The Scoping Ruling designates the following issues in scope for Track 3: (1) adoption of the 2026-2028 local capacity requirements; (2) adoption of the 2026 flexible capacity requirements; (3) the planning reserve margin (PRM) for 2026; (4) the slice-of-day (SOD) framework; (5) unforced capacity evaluations; (6) refinements to the incentive-based supply-side demand response qualifying capacity proposal; (7) the synchronization of Integrated Resource Plan (IRP) data collection with the local resource adequacy (RA) central procurement entity (CPE) framework data requirements; and (8) other time sensitive issues identified by Energy Division or parties in proposals.

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1 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.

2 *Assigned Commissioner's Amended Scoping Memo and Ruling*, Rulemaking (R.) 23-10-011 (Nov. 1, 2024): http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=544652400.

I. INTRODUCTION

The California Public Utilities Commission's (Commission) RA program is critical to ensuring sufficient supply is under contract to serve load in all hours and maintain reliability standards within the California Independent System Operator (CAISO) balancing authority area (BAA). RA supply constraints have made RA procurement increasingly expensive. As stated by Energy Division in its revised loss of load expectation (LOLE) study for 2026:

> RA prices have reached unprecedented levels that in many cases far exceed the marginal cost of new capacity. Notably, between 2017 and 2023 the weighted average price for RA capacity has increased by 349% from $2.46 kW-month to $11.05 kW-month. Additionally, the most recent Power Charge Indifference Adjustment (PCIA) Final RA market price benchmark reflects that System RA prices between 2023 and 2024 have nearly doubled, increasing from $14.37 to $28.65 kW-month. Equally concerning is some LSEs have indicated that in recent procurement solicitations, generators are offering multi-year contracts that would lock in these excessively high prices for the mid-term time horizon, most notably for existing capacity far in exceedance of its marginal cost.[3]

CalCCA agrees with Energy Division that these affordability concerns, the latest LOLE study results, and the October 30, 2024, Governor's Executive Order,[4] warrant consideration of price mitigation options within the RA program.[5] In evaluating Track 3 proposals, the Commission should elevate options that support affordable rates. The Commission should also seek to minimize Energy Division's and load serving entities' (LSE) time and administrative burden of data requests. With these objectives in mind, CalCCA recommends the Commission:

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[3] *Appendix B to Loss of Load Expectation Study for 2026: Revised Slice of Day Tool Analysis*, R.23-10-011 (Dec. 20, 2024), at 26-27 (LOLE Study Appendix B) (footnotes omitted): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M549/K797/549797826.PDF.

[4] *See* Executive Department State of California, Executive Order N-5-24 (Oct. 30, 2024): https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf.

[5] *See* LOLE Study Appendix B, at 28.

- Allow LSEs to transact load obligations on an hourly basis under the SOD framework to enable full optimization of RA resources and reduce costs for all LSEs, given hourly load obligation trading:
    - Is an administratively simple way to increase transactability under SOD;
    - Will promote affordability without compromising reliability;
    - Maintains LSEs' responsibility to meet RA requirements;
    - Can improve the ability to meet RA requirements under the SOD framework, as can be demonstrated in analyses of 2025 year-ahead RA (YARA) showings; and
    - Can be easily incorporated into the existing SOD showing template.
- Address co-located resources and RA needs, including:
    - Formalizing in the Track 3 Decision the determination made during Energy Division Staff office hours regarding allowing Partial Capacity Deliverability Status (PCDS) or Full Capacity Deliverability Status (FCDS) co-located generation to count for storage charging sufficiency requirements or RA requirements for on-site or off-site storage; and
    - Reevaluating accounting methodologies to allow energy-only (EO) co-located resources to count as RA under the SOD framework when such resources are limited to the deliverable megawatts (MW) at the point-of-interconnection (POI).
- Incorporate the local RA CPE data request process into the existing RA filing process.

II. THE COMMISSION SHOULD ALLOW LSES TO TRANSACT LOAD OBLIGATIONS ON AN HOURLY BASIS

CalCCA defines transactability as the ability to transact RA products in the same units denominated in setting RA requirements; in other words, if RA requirements are set on an hourly basis, some or all products should be transactable on an hourly basis. Transactability is a key component of the RA program that must be enhanced under the SOD program to allow LSEs to meet their compliance obligations simply, efficiently, and affordably. The SOD framework is designed to ensure the RA fleet provides grid reliability at all times of the day by requiring LSEs to demonstrate sufficient capacity to meet their load profile plus a PRM in all 24 hours of the "worst day" of the RA month.[6] Although the SOD framework sets 24 requirements and 24 net qualifying capacity(NQC) values, it currently does not allow LSEs to transact at the same granularity. Instead, the SOD framework continues to require monthly transactions. This means that if an LSE contracts for a resource, it must do so for the resource's NQC in all 24 hours for that month even if the LSE only has an open position in one hour. This lack of transactability could significantly challenge the LSEs' ability to meet their RA obligations in a cost-effective manner by increasing demand for RA and artificially constraining the RA market, resulting in over-procurement and increased ratepayer costs.

As discussed below, the Commission should allow LSEs to transact load obligations on an hourly basis, given that hourly load obligation trading: (1) is an administratively simple way to increase transactability under SOD; (2) will promote affordability without compromising reliability; (3) maintains LSEs' responsibility to meet RA requirements; (4) can improve the ability to meet RA requirements under the SOD framework, as can be demonstrated in analyses of 2025 YARA showings; and (5) can be easily incorporated into the existing SOD showing template.

A. Hourly Load Obligation Trading is an Administratively Simple Way to Increase Transactability Under SOD

Hourly load obligation trades proposed here would be bilateral transactions in which an LSE with open positions in some hours pays another LSE with long positions in those to show excess resources to cover its open positions. Hourly load obligation trading involves trading of LSE's hourly obligations – a product within the Commission's jurisdiction – only. Hourly load obligation trading does not involve generators (or their requirements) at all, but rather allows one LSE to pay another LSE to use the second LSE's resources to meet the first LSE's obligations. It

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[6] *See* D.22-06-050, *Decision Adopting Local Capacity Obligations for 2023-2025, Flexible Capacity Obligations for 2023, and Reform Track Framework*, R.21-10-002 (June 23, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF.

eliminates the need to modify the CAISO's outage substitution or the must offer obligation rules in any way. Hourly load obligation trading can be implemented with no CAISO impacts and, if desired, it can be improved with minor CAISO impacts to account for hourly load obligation trades in capacity procurement mechanism (CPM) cost allocation.[7] Incorporating hourly transactions on the load side keeps the process administratively simple for the Commission, the LSEs, and the generators. The Commission has previously expressed concerns with the ability to validate showings with hourly resource trading. While hourly transactions of loads *and* resources are more fitting with the SOD framework, if the Commission continues to see difficulty with administering hourly resource trading, it should at minimum allow hourly load obligation trading to better match availability with hourly requirements.

As described in section II.E below, this proposal would ensure RA obligations are fully accounted for following a trade by requiring both LSEs to document the trade on their RA

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[7] Because the CAISO will validate Commission-jurisdictional LSE plans by validating the gross peak hour under SOD, only hourly load transactions that occur during the gross peak hour would have impacts under CAISO RA processes. These impacts can be isolated to the LSEs conducting load transactions and avoid the CAISO entirely. The CAISO validates LSE RA plans against the LSE's load, as communicated through the CEC's load forecast process, plus a PRM. As such, there is no way for the LSE to communicate an hourly load obligation trade directly to the CAISO. This would result in a CPM cost allocation risk for the LSE paying another to take on its obligation in the gross peak hour *in the narrow instances when a deficiency not related to hourly load transactions occurs*. An LSE appearing deficient from a CAISO perspective due to an hourly load obligation trade that the CAISO cannot see should not trigger backstop because the LSE on the other side of the hourly load obligation trade would be required to show to CAISO the resources it is using to cover the additional load that it was paid to take on. In other words, the hourly load obligation trade would keep the system "whole" and should not trigger the need for backstop all else equal. Other deficiencies unrelated to the hourly load trade (e.g., another LSE having an individual deficiency) could trigger backstop, in which case the LSE paying another to take on its obligation would be exposed to backstop cost allocation as the CAISO views the LSE as being short since it does not have visibility to the load obligation trade. Given the coincident issues that must occur - a load obligation trade including the gross load hour and another LSE being short of RA in that hour, the probability of such a cost being imposed is minimal. This could be resolved in the long term by the Commission and the CAISO updating their processes such that the CAISO allocates CPM costs to the Commission and have the Commission allocate those costs to LSEs after taking into account hourly trades. Such an update should not be seen as a requirement to implement hourly load obligation trading. Instead, it should be viewed as a potential improvement that could be explored at the CAISO in a future stakeholder initiative.

showings. The Commission would be responsible for validating trades to ensure no double counting or loss of total RA obligation across hours resulting from load obligation trading. This is very similar to the checks the Commission performs today to ensure that a resource is not overclaimed.

If an LSE taking on an hourly load transaction unexpectedly ceases to provide LSE services, the responsibility for showing sufficient resources to cover the load transaction would revert back to the original LSE for the next showing. This is the same treatment that would occur if a resource swap or resource sale between two LSEs occurred. That is, if the resource is no longer under contract due to the LSE default, the scheduling coordinator for the resource would not file a supply plan for that resource on behalf of the LSE. For any situation in which the showing is already complete, the parties are expected to abide by the terms of the agreement.

B. Hourly Load Obligation Trading Will Promote RA Affordability Without Compromising Reliability

The ability to transact hourly under SOD encourages cost-effective procurement and an affordable RA program. The inability to transact at the same granularity as the requirement could increase RA costs in two primary ways:

- It produces an artificial RA shortage in the market when RA resources may be sufficient, leaving some LSE positions much longer than needed and other LSEs short;
  - Excess long positions increase the cost of procurement; and
  - Short positions lead to RA *compliance penalties* even though the system as a whole was sufficient.
- It drives up the cost of RA procurement for all customers by increasing demand and creating an artificial RA shortage.

Hourly load obligation trades will reduce artificial RA scarcity and minimize over-procurement by allowing LSEs to capture the diversity inherent in their load shapes and resource portfolios.

Therefore, the ability of LSEs to shape their portfolios to match their obligations will minimize procurement costs ultimately borne by customers through both lower prices and reduced over-procurement.

Hourly load trading has the potential to provide these affordability benefits while maintaining LSEs' RA obligations and the RA program's reliability targets. The LSE's obligation to serve its customers remains intact as discussed in section II.C., the associated costs of compliance remain with the original LSE, and the Commission can easily validate that all RA requirements continue to be met without overcounting shown resources as discussed in section II.E.

While it may be technically feasible for all LSEs to meet their SOD requirements relying only on swaps (*i.e.,* LSEs trading resources at the monthly level rather than hourly), there is significant difficulty in getting all the necessary transactions to line up to meet reliability through a bilateral market design. It is more likely that multiple transactions between multiple LSEs will be necessary to achieve compliance through swaps. While swaps and full resources procurement should be an option, they should not be the only options. A properly constructed load obligation trade will allow for the grid to be reliably maintained while buyers and sellers determine among themselves the value of the load obligation.

C. Hourly Load Obligation Trading Maintains LSEs' Responsibility to Meet RA Requirements

Importantly, trading obligations would not shift the responsibility of serving customer load, nor would it shift the responsibility of any compliance obligation. Section 380(c) provides:

> Each load-serving entity shall maintain physical generating capacity and electrical demand response adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves.[8]

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[8] Cal. Pub. Util. Code § 380(c).

In fact, trading a "load obligation" does not technically relieve an LSE of its obligation to serve load, it requires the LSE to procure sufficient products to meet the requirements. It remains the responsibility of the underlying guarantor, subject to penalties, that there will be sufficient RA to serve its load, whether this means procuring a resource or procuring a new "hourly load obligation" product. Trading a load obligation is thus a procurement product, rather than actual relief from a load obligation.

Hourly obligation trading simply allows another way for LSEs with open positions to comply with their RA obligation. For this reason, CalCCA does not propose to limit the amount of an LSE's compliance obligation that can be met by hourly load transactions. Hourly load obligation trading is a compliance mechanism and market participants should be able to choose any compliance mechanism available to it to meet its needs in the most cost-effective manner. If the solution is more cost effective for both the buyer and seller of the load obligation and reliability is met, then each party has paid its share to meet its obligations.

D. Analysis of 2025 YARA Showings Demonstrates Hourly Load Transactions Can Improve the Ability to Meet RA Requirements Under the SOD Framework

Decision (D.) 22-06-050 found that "if transactability and inefficiency concerns arise once the new 24-hour framework is implemented, the Commission may consider proposals to include hourly obligation trading."[9] CalCCA's analysis of its members' first binding YARA showings demonstrates that hourly load trading could improve the transactability and efficiency of the SOD program. Figure 1 below shows aggregate long positions of CalCCA members relative to their 90 percent YARA requirements (blue bars) and aggregate short positions of

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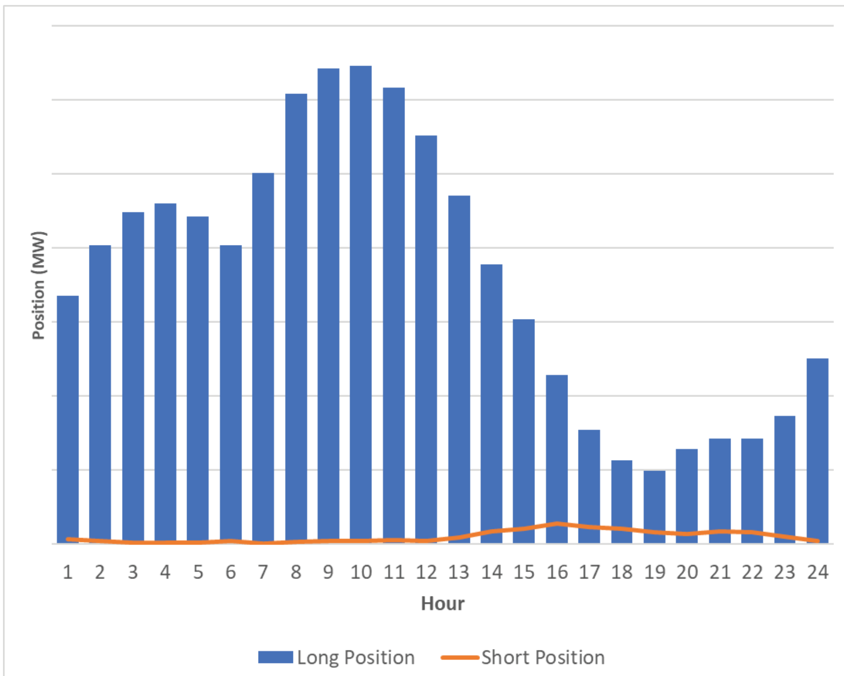
[9] D.22-06-050, *Decision Adopting Local Capacity Obligations for 2023-2025, Flexible Capacity Obligations for 2023, and Reform Track Framework*, R.21-10-002 (June 23, 2022), at 97: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF.

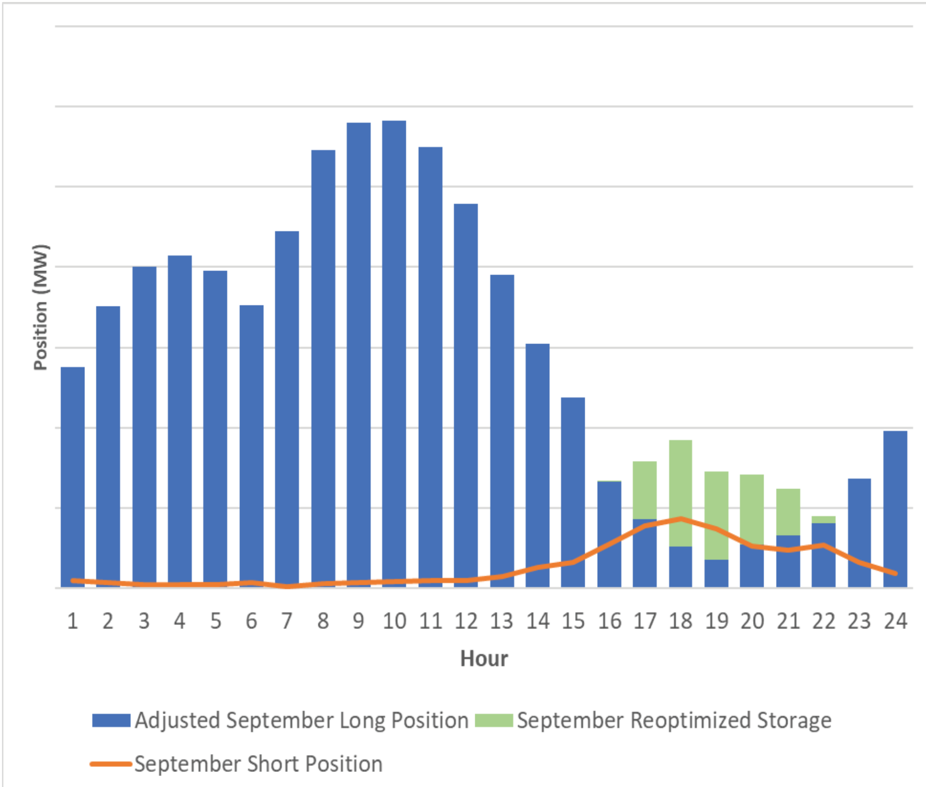
CalCCA members relative to their 90 percent YARA requirements (orange line) in each hour. The data indicates that the ability to transact load obligations on an hourly basis would have increased compliance with SOD YARA requirements. In fact, on an aggregated basis, long positions could have fully covered short positions.

Figure 1: SOD Aggregate Short Positions vs. Long Positions for CCA September YARA Showings



In addition, Figure 2 below demonstrates that long positions in the YARA could fully cover short YARA positions *and* limit the need for additional resource procurement in the forthcoming 100 percent month-ahead RA (MARA) requirements to just two hours. If storage was reoptimized to minimize MARA deficiencies, the deficiency in those two hours could potentially be eliminated fully. Figure 2 shows aggregate long positions (blue bars) and short positions (orange line) relative to aggregate 100 percent MARA requirements. Figure 2 also shows how storage showings could be reoptimized to fully close short positions (green bars).

Figure 2: SOD Aggregate Short Positions vs. Long Positions with 100 Percent Requirement using CCA September YARA Showings



These findings demonstrate that the hourly load transactability has the potential to minimize or eliminate LSE deficiencies for the YARA showings and limit the need for additional resource procurement between the YARA and MARA. In short, for the YARA, the system reliability needs are covered in aggregate by the showings of all CCAs even though individual CCAs had deficiencies. For the MARA, when shown storage is reoptimized, the system reliability needs are covered in aggregate by the showings of all CCAs even though individual CCAs had deficiencies. Avoiding purchases of RA through trade can potentially reduce costs by as much as $180 million per year, according to CalCCA analysis.[10] Artificial barriers to

[10] CalCCA's analysis of CCA YARA filings for 2025 finds that trade between CCAs eliminates the need to purchase about $62 million of RA across the five summer months, assuming the price for RA in each month is similar to the weighted-average price of RA bought by LSEs in the period between the

compliance should be eliminated to avoid the perverse outcome of artificially constraining RA supply, driving up RA prices or penalizing LSEs while the system reliability has been met. Allowing hourly load transactions would go a long way in removing artificial barriers.

E. The Commission Can Easily Incorporate Hourly Load Transactions into the Existing Slice-of-Day Showing Template

The Commission can easily accommodate and validate load transaction showings within the existing template. The following examples show how a load obligation transaction can successfully be shown and validated within the existing template for both the entities selling and purchasing obligations. Also included are examples where the transaction between buyer and seller cannot be validated, and the actions the Commission would take as a result. This validation process is very similar to the existing process the Commission uses to validate RA showings by matching them with generator supply plans.

In the description and figures below, the only changes that LSEs will be allowed to make to the RA Showing Template are on tabs where LSE entries are allowed currently. That is, the LSE will continue to make changes, including load obligation trades, using only the Certification, LSE Showing, Resource Custom Profiles, User-Defined Resources, and Profile Optimization tabs. All other tabs depicted in the figures below would use the data in these tabs, including load obligation trades, to reflect the compliance status of the LSE.

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year-ahead and month-ahead filings observed in the summer months of 2024. CalCCA estimates that trade between all LSEs could reduce RA demand by 70 percent more than trade between CCAs, based on a comparison of the short positions for CCAs and short positions for all LSEs in the Commission's analysis of test-year filings, increasing the direct benefits to $105 million per year. In addition, lower demand for RA puts downward pressure on the price for RA. Assuming that California LSEs purchase about 20 gigawatts (GW) of RA each month at market prices and that the price elasticity of RA is $1/kilowatt-month per GW of RA demand, the reduction in RA demand from trade indirectly lowers the cost of RA for all California LSEs by about $77 million per year. Together, the direct and indirect benefits of trade could be as high as $180 million per year.

1. Example of a Successful Load Obligation Transaction

In this example, LSE 1 and LSE 2 enter into a load obligation trade where LSE 2 sells an obligation to LSE 1 (*i.e.,* LSE 2 pays LSE 1 to cover a portion of its obligation). As a starting point, Figure 3, using the Hourly Availability tab of the *RA Showing Template Rev 34*,[11] shows that LSE 1 has met its obligation in all hours and has some excess capacity in all hours. LSE 2 is short in hour ending (HE) 15 through 20.

Figure 3: Hourly Availability tab RA Showing Template Rev 34 for LSE 1 (Left) and LSE 2 (Right)

In addition, the Check Capacity tab from the RA showing Template Rev 34 shows the information numerically as depicted, in Figure 4.

[11] *See* Resource Adequacy Compliance Materials, LSE Showing Template, Version 34: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

Figure 4: Check Capacity Tab RA Showing Template Rev 34 for LSE 1 and LSE2

LSE 1

Contract ID	Resource ID	MW																							
		HE 1	HE 2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
Requirements		-302	-282	-271	-274	-295	-326	-365	-391	-422	-458	-491	-525	-547	-569	-585	-582	-564	-523	-492	-485	-464	-422	-381	-345
DR Allocation		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	19	18	17	17	0	0	0
CAM Peakers	CAM Peaker Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	5	5	5	5	5	5	5	0	0
CAM Storage	CAM Storage Allocation Multi Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3	3	3	0	0	0
CAM Storage	CAM Storage Allocation Single Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	5	5	0	0	0
Other CAM Allocation		76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
	PALOMR_2_PL1X3	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425
	TOPAZ_2_SOLAR	0	0	0	0	0	9	64	120	151	167	177	179	178	175	167	153	125	77	17	0	0	0	0	0
		199	**219**	**230**	**226**	**206**	**183**	**200**	**230**	**230**	**210**	**187**	**155**	**132**	**111**	**88**	**76**	**86**	**86**	**56**	**46**	**65**	**84**	**120**	**156**

LSE 2

Contract ID	Resource ID	MW																							
		HE 1	HE 2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
Requirements		-175	-162	-152	-145	-139	-138	-133	-134	-139	-146	-155	-169	-188	-208	-229	-246	-255	-288	-293	-283	-242	-228	-211	-194
DR Allocation		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	8	7	7	7	0	0	0
CAM Peakers	CAM Peaker Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	2	0	0
CAM Storage	CAM Storage Allocation Multi Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0
CAM Storage	CAM Storage Allocation Single Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	0	0	0
Other CAM Allocation		30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
	ARCOGN_2_UNITS	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
	ATHOS_5_AP2X2	0	0	0	0	0	1	7	10	12	12	12	12	12	12	12	11	10	6	1	0	0	0	0	0
	GEYS11_7_UNIT11	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86
	JOANEC_2_STABT2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15	0	0	0
	VOYAGR_2_VOYWD2	78	72	64	58	51	39	29	18	11	8	10	14	19	29	39	53	65	74	80	82	85	85	83	81
		70	**77**	**79**	**80**	**78**	**69**	**69**	**61**	**50**	**41**	**34**	**24**	**10**	**1**	**-9**	**-13**	**-4**	**-14**	**-18**	**-8**	**36**	**26**	**39**	**53**

LSE 1 agrees to purchase a load obligation for HE 15 through HE 20 from LSE 2. After completing the transaction, the LSEs show this transaction in the LSE Showing tab of the RA Showing Template Rev 34, as demonstrated in Figure 5. So that the Commission can easily identify load obligation trades, the Resource ID column is marked as "Load Obligation Purchase/Sale" and the SCID or counterparty column lists the LSE counterparty to the transaction. The "NQC under contract column" could depict the maximum amount of the load obligation trade. Since this amount will be for specific hours and could vary by hour, the parties will need to mark the "Use Default Profile" cell as "false." The parties will use the "Resource Custom Profile" tab to depict the quantities and hours transacted, as demonstrated in Figure 6. The Load Obligation transaction is highlighted in yellow in both figures.

Figure 5: LSE Showing Tab of the RA Showing Template Rev 34

LSE 1

Contract ID	Resource ID	NQC Under Contract (MW)	Local RA (MW)	Committed Flexible RA (MW)	Capacity Effective Start Date	Capacity Effective End Date	SCID or Counterparty if not available	MCC Bucket 4	Unspecified Import	Use Default Profile
CAM Storage	CAM Storage Allocation Single Cycle	4.58	0.00	0.00	2025-07-01	2025-07-31	Allocation	FALSE	FALSE	TRUE
CAM Storage	CAM Storage Allocation Multi Cycle	2.92	0.00	0.00	2025-07-01	2025-07-31	Allocation	FALSE	FALSE	TRUE
CAM Peakers	CAM Peaker Allocation	4.61	0.00	0.00	2025-07-01	2025-07-31	Allocation	FALSE	FALSE	TRUE
	PALOMR_2_PL1X3	425.00	425.00	425.00	2025-07-01	2025-07-31	Gen 1	FALSE	FALSE	TRUE
	TOPAZ_2_SOLAR	125.00	0.00	0.00	2025-07-01	2025-07-31	Solar 1	FALSE	FALSE	TRUE
	Load Obligation Purchase	18.00	0.00	0.00	2025-07-01	2025-07-31	LSE 2	FALSE	FALSE	FALSE

LSE 2

Contract ID	Resource ID	NQC Under Contract (MW)	Local RA (MW)	Committed Flexible RA (MW)	Capacity Effective Start Date	Capacity Effective End Date	SCID or Counterparty if not available	MCC Bucket 4	Unspecified Import	Use Default Profile
CAM Storage	CAM Storage Allocation Single Cycle	1.84	0.00	0.00	2025-01-01	2025-12-31	Allocation	FALSE	FALSE	TRUE
CAM Storage	CAM Storage Allocation Multi Cycle	1.18	0.00	0.00	2025-01-01	2025-12-31	Allocation	FALSE	FALSE	TRUE
CAM Peakers	CAM Peaker Allocation	1.86	0.00	0.00	2025-01-01	2025-12-31	Allocation	FALSE	FALSE	TRUE
	JOANEC_2_STABT2	15.00	0.00	30.00	2025-01-01	2025-12-31	BESS 2	FALSE	FALSE	TRUE
	ARCOGN_2_UNITS	50.00	0.00	0.00	2025-01-01	2025-12-31	CHP 2	FALSE	FALSE	TRUE
	ATHOS_5_AP2X2	10.00	0.00	0.00	2025-01-01	2025-12-31	Solar 2	FALSE	FALSE	TRUE
	GEYS11_7_UNIT11	86.00	0.00	86.00	2025-01-01	2025-12-31	Geothermal 2	FALSE	FALSE	TRUE
	VOYAGR_2_VOYWD2	65.00	0.00	0.00	2025-01-01	2025-12-31	Wind 2	FALSE	FALSE	TRUE
	Load Obligation Sale	18.00	0.00	0.00	2025-07-01	2025-07-31	LSE 1	FALSE	FALSE	FALSE

Figure 6: Resource Custom Profile RA Showing Template Rev 34

LSE 1

Contract ID	Resource ID	Resource SubID	MW																						
			HE 1	HE 2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
	Load Obligation Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	13	5	14	18	8	0	0	0	0

LSE 2

Contract ID	Resource ID	Resource SubID	MW																						
			HE 1	HE 2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
	Load Obligation Sale		0	0	0	0	0	0	0	0	0	0	0	0	0	0	-10	-13	-5	-14	-18	-8	0	0	0	0
CPUC Check for differences			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

As shown in Figure 6, the Commission can easily check the information input by LSEs on the Resource Custom Profile tab to ensure that each hour of the load obligation purchase is matched by a load obligation sale. The example shows load obligation purchases as a positive as it is adding to the LSEs obligation while the load obligation sale is shown as a negative as it is decreasing the LSEs obligation. This information can then be incorporated into the load obligation of each LSE within the RA Showing Template and, in this case, will result in Figure 7 and Figure 8 which reflect the revised position of each LSE.

Figure 7: Updated Check Capacity Tab RA Showing Template Rev 34

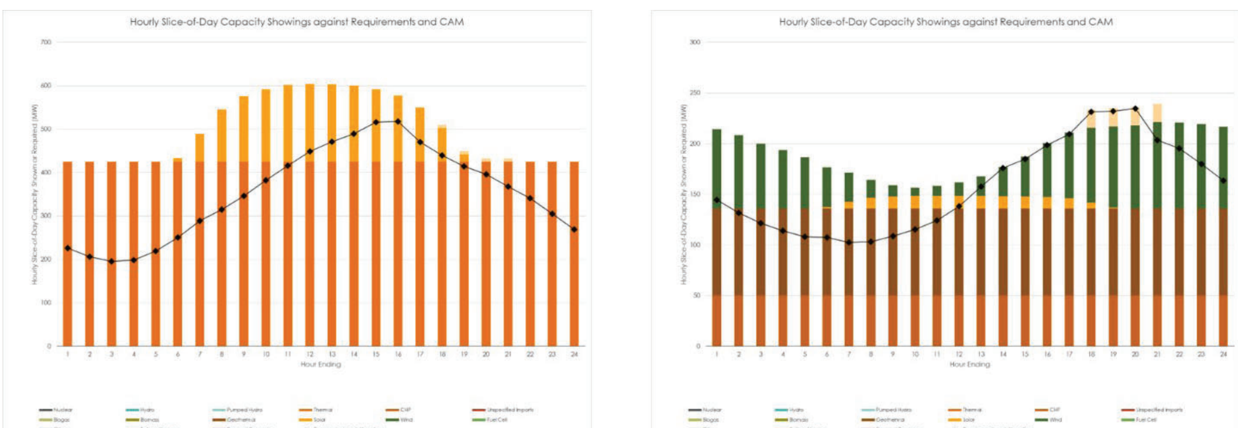
LSE 1

Contract ID	Resource ID	MW																							
		HE 1	HE 2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
Requirements		-302	-282	-271	-274	-295	-326	-365	-391	-422	-458	-491	-525	-547	-569	-595	-595	-569	-537	-510	-493	-464	-422	-381	-345
DR Allocation		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	19	18	17	17	0	0	0
CAM Peakers	CAM Peaker Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	5	5	5	5	5	5	5	0	0
CAM Storage	CAM Storage Allocation Multi Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3	3	3	0	0	0
CAM Storage	CAM Storage Allocation Single Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	5	5	0	0	0
Other CAM Allocation		76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
	PALOMR_2_PL1X3	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425
	TOPAZ_2_SOLAR	0	0	0	0	0	9	64	120	151	167	177	179	178	175	167	153	125	77	17	0	0	0	0	0
		199	**219**	**230**	**226**	**206**	**183**	**200**	**230**	**230**	**210**	**187**	**155**	**132**	**111**	**78**	**63**	**81**	**72**	**38**	**38**	**65**	**84**	**120**	**156**

LSE 2

Contract ID	Resource ID	MW																							
		HE 1	HE 2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
Requirements		-175	-162	-152	-145	-139	-138	-133	-134	-139	-146	-155	-169	-188	-208	-219	-233	-250	-274	-275	-275	-242	-228	-211	-194
DR Allocation		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	8	7	7	7	0	0	0
CAM Peakers	CAM Peaker Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	2	0	0
CAM Storage	CAM Storage Allocation Multi Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0
CAM Storage	CAM Storage Allocation Single Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	2	0	0	0
Other CAM Allocation		30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
	ARCOGN_2_UNITS	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
	ATHOS_5_AP2X2	0	0	0	0	0	1	7	10	12	12	12	12	12	12	12	11	10	6	1	0	0	0	0	0
	GEYS11_7_UNIT11	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86
	JOANEC_2_STABT2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15	0	0	0
	VOYAGR_2_VOYWD2	78	72	64	58	51	39	29	18	11	8	10	14	19	29	39	53	65	74	80	82	85	85	83	81
		70	**77**	**79**	**80**	**78**	**69**	**69**	**61**	**50**	**41**	**34**	**24**	**10**	**1**	**1**	**0**	**1**	**0**	**0**	**0**	**36**	**26**	**39**	**53**

Figure 8: Updated Hourly Availability Chart RA Showing Template Rev 34



This example is one possible method that load obligation transactions can be shown by LSEs using the existing showing template. The next sections show how errors in the showing can be identified by the Commission.

2. Example of Load Obligation Transactions Containing Errors

The examples below demonstrate how hourly load transaction showing errors could be easily detected and easily corrected using the existing validation process. This process follows the process used today when an LSE shows a resource that is not included in a supply plan.

The first example involves a load obligation transaction in which the party showing a sale does not match with a purchasing party. This could occur where the load obligation seller lists a buyer who does not show the load obligation purchase on their showing or where the load obligation seller lists the incorrect LSE as the buyer. The latter is depicted in Figure 9.

Figure 9: Load Obligation Sale does not Match Load Purchasing LSE Showing

LSE 1

Contract ID	Resource ID	NQC Under Contract (MW)	Local RA (MW)	Committed Flexible RA (MW)	Capacity Effective Start Date	Capacity Effective End Date	SCID or Counterparty if not available	MCC Bucket 4	Unspecified Import	Use Default Profile
CAM Storage	CAM Storage Allocation Single Cycle	4.50	0.00	0.00	2025-07-01	2025-07-31	Allocation	FALSE	FALSE	TRUE
CAM Storage	CAM Storage Allocation Multi Cycle	2.92	0.00	0.00	2025-07-01	2025-07-31	Allocation	FALSE	FALSE	TRUE
CAM Peakers	CAM Peaker Allocation	4.61	0.00	0.00	2025-07-01	2025-07-31	Allocation	FALSE	FALSE	TRUE
	PALOMR_2_PL1X3	425.00	425.00	425.00	2025-07-01	2025-07-31	Gen 1	FALSE	FALSE	TRUE
	TOPAZ_2_SOLAR	125.00	0.00	0.00	2025-07-01	2025-07-31	Solar 1	FALSE	FALSE	TRUE
	Load Obligation Purchase	18.00	0.00	0.00	2025-07-01	2025-07-31	LSE 2	FALSE	FALSE	FALSE

LSE 2

Contract ID	Resource ID	NQC Under Contract (MW)	Local RA (MW)	Committed Flexible RA (MW)	Capacity Effective Start Date	Capacity Effective End Date	SCID or Counterparty if not available	MCC Bucket 4	Unspecified Import	Use Default Profile
CAM Storage	CAM Storage Allocation Single Cycle	1.84	0.00	0.00	2025-01-01	2025-12-31	Allocation	FALSE	FALSE	TRUE
CAM Storage	CAM Storage Allocation Multi Cycle	1.18	0.00	0.00	2025-01-01	2025-12-31	Allocation	FALSE	FALSE	TRUE
CAM Peakers	CAM Peaker Allocation	1.86	0.00	0.00	2025-01-01	2025-12-31	Allocation	FALSE	FALSE	TRUE
	JOANEC_2_STABT2	15.00	0.00	30.00	2025-01-01	2025-12-31	BESS 2	FALSE	FALSE	TRUE
	ARCOGN_2_UNITS	50.00	0.00	0.00	2025-01-01	2025-12-31	CHP 2	FALSE	FALSE	TRUE
	ATHOS_5_AP2X2	10.00	0.00	0.00	2025-01-01	2025-12-31	Solar 2	FALSE	FALSE	TRUE
	GEYS11_7_UNIT11	86.00	0.00	86.00	2025-01-01	2025-12-31	Geothermal 2	FALSE	FALSE	TRUE
	VOYAGR_2_VOYWD2	65.00	0.00	0.00	2025-01-01	2025-12-31	Wind 2	FALSE	FALSE	TRUE
	Load Obligation Sale	18.00	0.00	0.00	2025-07-01	2025-07-31	LSE 3	FALSE	FALSE	FALSE

The error, highlighted in red, shows that LSE 1 claims to have purchased a load obligation from LSE 2. However, LSE 2 claims to have sold a load obligation to LSE 3. In this case, the Commission would notify LSE 1 and LSE 2 that their showing of a load obligation trade was not validated by the LSE shown in the template. The LSEs would then have the opportunity to correct their showing and resubmit. This process follows the process used today when an LSE shows a resource that is not included in a supply plan.

The second example shows a circumstance in which the LSEs to the load obligation trade do not show the same amount of NQC (the maximum MWs of the load obligation trade). The error is highlighted in red in Figure 10.

Figure 10: MWs do not match in Load Obligation Trade on Check Capacity Tab of RA Showing Template Rev 34

LSE 1

Contract ID	Resource ID	NQC Under Contract (MW)	Local RA (MW)	Committed Flexible RA (MW)	Capacity Effective Start Date	Capacity Effective End Date	SCID or Counterparty if not available	MCC Bucket 4	Unspecified Import	Use Default Profile
CAM Storage	CAM Storage Allocation Single Cycle	4.58	0.00	0.00	2025-07-01	2025-07-31	Allocation	FALSE	FALSE	TRUE
CAM Storage	CAM Storage Allocation Multi Cycle	2.92	0.00	0.00	2025-07-01	2025-07-31	Allocation	FALSE	FALSE	TRUE
CAM Peakers	CAM Peaker Allocation	4.61	0.00	0.00	2025-07-01	2025-07-31	Allocation	FALSE	FALSE	TRUE
	PALOMR_2_PL1X3	425.00	425.00	425.00	2025-07-01	2025-07-31	Gen 1	FALSE	FALSE	TRUE
	TOPAZ_2_SOLAR	125.00	0.00	0.00	2025-07-01	2025-07-31	Solar 1	FALSE	FALSE	TRUE
	Load Obligation Purchase	14.00	0.00	0.00	2025-07-01	2025-07-31	LSE 2	FALSE	FALSE	FALSE

LSE 2

Contract ID	Resource ID	NQC Under Contract (MW)	Local RA (MW)	Committed Flexible RA (MW)	Capacity Effective Start Date	Capacity Effective End Date	SCID or Counterparty if not available	MCC Bucket 4	Unspecified Import	Use Default Profile
CAM Storage	CAM Storage Allocation Single Cycle	1.84	0.00	0.00	2025-01-01	2025-12-31	Allocation	FALSE	FALSE	TRUE
CAM Storage	CAM Storage Allocation Multi Cycle	1.18	0.00	0.00	2025-01-01	2025-12-31	Allocation	FALSE	FALSE	TRUE
CAM Peakers	CAM Peaker Allocation	1.86	0.00	0.00	2025-01-01	2025-12-31	Allocation	FALSE	FALSE	TRUE
	JOANEC_2_STABT2	15.00	0.00	30.00	2025-01-01	2025-12-31	BESS 2	FALSE	FALSE	TRUE
	ARCOGN_2_UNITS	50.00	0.00	0.00	2025-01-01	2025-12-31	CHP 2	FALSE	FALSE	TRUE
	ATHOS_5_AP2X2	10.00	0.00	0.00	2025-01-01	2025-12-31	Solar 2	FALSE	FALSE	TRUE
	GEYS11_7_UNIT11	86.00	0.00	86.00	2025-01-01	2025-12-31	Geothermal 2	FALSE	FALSE	TRUE
	VOYAGR_2_VOYWD2	65.00	0.00	0.00	2025-01-01	2025-12-31	Wind 2	FALSE	FALSE	TRUE
	Load Obligation Sale	18.00	0.00	0.00	2025-07-01	2025-07-31	LSE 1	FALSE	FALSE	FALSE

In this case, the Commission would again notify LSE 1 and LSE 2 that their showing of a load obligation trade was not validated in the template. The LSEs would then have the opportunity to correct their showing and resubmit. This process follows the process used today when an LSE shows a resource for an amount that does not match in a supply plan.

The final example depicts an error in which the LSEs show different MW values in the hourly profile of the Custom Resource Profile tab of the RA Showing Template. The error is highlighted in red in Figure 11 on the row showing the CPUC check for differences. The LSEs would then have the opportunity to correct their showing and resubmit. This process follows the process used today when an LSE shows a resource that is not included in a supply plan.

Figure 11: Hourly Profile Error in Resource Custom Profile tab RA Showing Template Rev 34

LSE 1

Contract ID	Resource ID	Resource SubID	MW																							
			HE 1	HE 2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
	Load Obligation Purchase		0	0	0	0	0	0	0	0	0	0	0	0	10	13	5	14	18	8	0	0	0	0	0	0

LSE 2

Contract ID	Resource ID	Resource SubID	MW																							
			HE 1	HE 2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
	Load Obligation Sale		0	0	0	0	0	0	0	0	0	0	0	0	0	0	-10	-13	-5	-14	-18	-8	0	0	0	0
CPUC Check for differences			0	0	0	0	0	0	0	0	0	0	0	0	10	13	-5	1	13	-6	-18	-8	0	0	0	0

These examples demonstrate that hourly load obligation trade showing errors can be easily detected and corrected using the existing processes for showing corrections.

III. THE COMMISSION SHOULD ADDRESS CO-LOCATED GENERATION AND RA NEEDS

The Commission should address two issues regarding co-located generation and RA processes, arising from the transition to SOD. *First*, the Commission should issue a formal decision incorporating in the RA counting rules the methodology for co-located deliverable resources clarified through Energy Division Staff's extensive office hours process. Addressing the issue formally will provide needed certainty to LSEs. *Second*, the Commission should reevaluate opportunities to allow EO co-located resources that share a POI with a deliverable resource to count as RA under the SOD framework. Ensuring that LSEs can maximize the use of their resources to meet RA requirements, especially under SOD, supports the goal of affordability by preventing over-procurement.

A. The Commission Should Formalize in the Track 3 Decision Energy Division's Determination on PCDS/FCDS Co-located Generation Counting for Storage Charging Sufficiency Requirements or RA Requirements for On-Site or Off-Site Storage

The Commission should formalize in the Track 3 Decision the determination made during Energy Division Staff office hours regarding allowing PCDS or FCDS co-located generation to count for storage charging sufficiency requirements or RA requirements for on-site or off-site storage. As described below, Energy Division Staff allowed such resources to count if the combination of shown generation plus shown storage does not exceed the deliverable MW at the POI in the same hour. Formalizing this finding in the Track 3 Decision will provide needed certainty to LSEs.

For co-located resource RA counting under SOD, D.23-04-010 adopted the existing additive qualifying capacity (QC) methodology updated to use the exceedance methodology for the wind and solar component.[12] The additive methodology calculates the renewable component's QC the same as standalone renewable resources' QC values and the storage component's QC value the same as standalone storage resources' QC values.[13] The total QC value of a co-located resource equals the sum of the two components, limited by the POI limit and the SOD compliance tool's storage charging sufficiency test, which ensures LSEs show sufficient excess generation to charge shown storage.[14] LSEs can meet the storage charging sufficiency test with EO generation only if the EO generation is used to charge storage that is located at the same POI.[15]

In preparation for the 2025 YARA showings, Energy Division included a "Deliverability MW" column in the Master Resource Database to represent the maximum capacity or proportion of a resource that is considered deliverable to the grid if less than its nameplate. The Deliverability MW value would cap the amount an LSE could show in its RA showing. Initially, Deliverability MW values were defined as the lower of:

- A deliverability reduction due to a resource's deliverability status and, if applicable, the 2025 NQC deliverability study limits; or
- A POI limit for co-located resources that share a POI and for which the limit was binding. For a co-located solar resource, the Deliverability MW was calculated as the POI limit minus the NQC of its paired storage resource.

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12 *See* D.23-04-010, *Decision on Phase 2 of the Resource Adequacy Reform Track*, R.21-10-002 (Apr. 6, 2023) (Reform Track Decision), at 38: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M505/K753/505753716.PDF.

13 See *2025 Resource Adequacy and Slice of Day Guide* (Sept. 25, 2024), at 5: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/guides-and-resources/2025-ra-slice-of-day-filing-guide121724.pdf.

14 *Ibid.*

15 *See* Reform Track Decision, at 38.

Following concerns that these caps were unnecessarily restrictive, Energy Division, in consultation with the CAISO and stakeholders, updated the Deliverability MW value for resources that fall into the second category to allow the affected co-located solar resources to count up to their full deliverable capacity. This change effectively allows LSEs to show co-located generation with PCDS or FCDS for RA or charging sufficiency requirements up to the deliverable POI, as long as the combination of generation plus storage does not exceed the deliverable POI in any individual hour.

The Commission should formalize this change in the Track 3 decision to allow PCDS or FCDS co-located generation to count for storage charging sufficiency requirements or RA requirements for on-site or off-site storage if the combination of shown generation plus shown storage does not exceed the deliverable MW at the POI in the same hour.

B. The Commission Should Reevaluate Accounting Methodologies to Allow EO Co-located Resources to Count as RA Under the SOD Framework

The Commission should, with input from LSEs, generators, and the CAISO, reevaluate accounting methodologies to allow for co-located resource counting and deliverability under the SOD framework when a portion or all of the generation component is EO. This effort will promote RA affordability by unlocking additional capacity that can be shown for RA and storage charging SOD requirements while maintaining reliability by preserving deliverability limits at the POI. Expanding opportunities for co-located resources currently defined as EO resources to provide reliability value is increasingly important given the base portfolio in the 2023-2024 Transmission Planning Process includes a significant amount of EO resources, including 23,311 MW of EO solar in 2035 compared to 15,636 MW of FCDS solar.[16]

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[16] See *2023-2024 Transmission Plan* (May 23, 2024), at 65: https://stakeholdercenter.caiso.com/InitiativeDocuments/BOARDAPPROVED_2023-2024_TransmissionPlan.pdf.

In the context of this reevaluation and discussion with stakeholders, the Commission can address three fundamental concerns to ensure that: (1) the showing of the two resources in any hour does not exceed the POI; (2) must-offer obligations are imposed on both resources; and (3) deliverability limits at the POI are not exceeded when the co-located resource has multiple offtakers. Each concern is addressed in turn below.

1. The Commission Can Ensure the Showing of the Co-located Resources in Any Hour Do Not Exceed the POI

The Commission must ensure that the showing of the two resources that are co-located do not exceed the deliverable MW at the POI in any hour. Deliverability for co-located resources is assessed for each individual generation and storage component at the same POI.[17] As a result, otherwise reliable resources during certain hours under SOD may be ignored strictly due to reviewing deliverability on a daily basis instead of adapting to the SOD structure.

Grid deliverability is not dependent on the type of generator but on the injection of electrons at a specific location. Co-locating renewable and energy storage brings benefits to the grid in that the storage is likely to inject electrons in hours that the renewable resource does not. Due to the "duck curve,"[18] storage is added to solar at a POI to extend generation from that location into the evening when solar is no longer producing. Allowing generation to be shown in all hours up to the deliverable POI under SOD allows for reliable grid operation without overbuilding the transmission to unnecessarily make the point of interconnection capable of delivering the output of both devices simultaneously since this generation profile is highly

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[17] This is unlike hybrid resources, which deliverability status based only on the available deliverability at the POI, not based upon the individual generation and storage components.

[18] The "Duck Curve" is a phenomenon identified by the CAISO that is caused by the large volume of renewable resources, particularly solar, to serve load. This can cause the load served net of solar in the middle of the day to decrease due to high solar irradiance. However, at sunset, when loads are still high and solar generation decreases, the net load shows a large increase that must be met by other resources.

unlikely. If the Commission allows co-located generation to count up to the deliverable POI, such a rule will be consistent with how resources in hybrid configurations can be shown.

The initial wave of storage was deployed in either co-located or hybrid systems, next to existing solar generation. In many instances, for co-located resources, the FCDS of the existing solar resource was shifted from the solar facility to the storage, reducing the available solar generation output available for charging sufficiency across the resources. Additionally, the bulk of many new contracts LSEs are signing are for co-located solar plus storage where the FCDS will very likely be placed on the storage, resulting in increasing amounts of charging sufficiency needed for the storage resources while limiting the amount of solar output that can be used for charging sufficiency across an LSE's entire portfolio. Allowing a broader set of resources at deliverable POIs to meet SOD requirements will increase RA supply and put downward pressure on high RA prices.

The Commission and stakeholders should develop a framework that ensures that the combination of shown generation plus shown storage does not exceed the deliverable MW at the POI *in the same hour*. The examples below demonstrate a showing that complies with this requirement (Figure 12) and another showing that does not (Figure 13). The example in Figure 12 demonstrates how a 100 MW EO solar resource and 50 MW storage resource at the same POI with 100 MW of deliverability can be shown without exceeding the deliverable MW at the POI in any hour.

Figure 12: Co-Located Resource Showing with EO Solar and FCDS Storage That Does Not Exceed the Deliverable MW at the POI in Any Hour

Variable	Value (MW)
Solar Resource	100
Storage Resource	50
POI	100

Solar Exceedance Factor	
HE	Exceedance Factor
1	0.00
2	0.00
3	0.00
4	0.00
5	0.00
6	0.01
7	0.25
8	0.65
9	0.75
10	0.79
11	0.80
12	0.80
13	0.79
14	0.78
15	0.77
16	0.70
17	0.39
18	0.05
19	0.00
20	0.00
21	0.00
22	0.00
23	0.00
24	0.00

Co-located (EO Solar + FCDS Storage)		
Solar	Storage	Total
0.00	0	0.00
0.00	0	0.00
0.00	0	0.00
0.00	0	0.00
0.00	0	0.00
0.68	0	0.68
24.69	0	24.69
64.51	0	64.51
75.13	0	75.13
79.03	0	79.03
79.66	0	79.66
79.64	0	79.64
79.20	0	79.20
78.28	0	78.28
77.14	0	77.14
69.65	0	69.65
38.96	0	38.96
4.67	0	4.67
0.00	50	50.00
0.00	50	50.00
0.00	50	50.00
0.00	50	50.00
0.00	0	0.00
0.00	0	0.00

In Figure 12, the solar resource is shown in HE 6 through HE 18 and the storage resource is shown in HE 19 through HE 22. Both the solar and storage can provide RA value without exceeding the deliverable MW at the POI.

Figure 13 demonstrates non-compliance with the requirement to not exceed the deliverable POI in any hour. Here, the storage resource is shown in HE 16 through HE 19, resulting in the solar and storage shown exceeding the deliverable MW at the POI in HE 16 (shown in red in Figure 13). This exceedance will therefore result in non-compliance with the requirement not to exceed the deliverable POI in any hour.

Figure 13: Co-Located Resource Showing with EO Solar and FCDS Storage Exceeding the Deliverable MW at the POI in Certain Hours

Variable	Value (MW)
Solar Resource	100
Storage Resource	50
POI	100

Solar Exceedance Factor		Co-located (EO Solar + FCDS Storage)		
HE	Exceedance Factor	Solar	Storage	Total
1	0.00	0.00	0	0.00
2	0.00	0.00	0	0.00
3	0.00	0.00	0	0.00
4	0.00	0.00	0	0.00
5	0.00	0.00	0	0.00
6	0.01	0.68	0	0.68
7	0.25	24.69	0	24.69
8	0.65	64.51	0	64.51
9	0.75	75.13	0	75.13
10	0.79	79.03	0	79.03
11	0.80	79.66	0	79.66
12	0.80	79.64	0	79.64
13	0.79	79.20	0	79.20
14	0.78	78.28	0	78.28
15	0.77	77.14	0	77.14
16	0.70	69.65	50	119.65
17	0.39	38.96	50	88.96
18	0.05	4.67	50	54.67
19	0.00	0.00	50	50.00
20	0.00	0.00	0	0.00
21	0.00	0.00	0	0.00
22	0.00	0.00	0	0.00
23	0.00	0.00	0	0.00
24	0.00	0.00	0	0.00

These examples demonstrate how co-located showings can allow for showings of EO resources while maintaining deliverability limits and reliability requirements.

2. The Commission Should Coordinate with the CAISO to Ensure Co-Located EO Resources that Do Not Exceed Deliverability Limits at the POI Have a Must Offer Obligation

The Commission should coordinate with the CAISO to ensure co-located EO Resources that do not exceed deliverability limits at the POI have a must-offer obligation (MOO). The CAISO only imposes a MOO on resources with deliverability status. While in Figure 12, both the solar and the storage can be shown without exceeding the deliverable MW at the POI, if the solar is classified as EO, it will not have a corresponding MOO from the CAISO without a change to CAISO rules. The Commission should therefore coordinate with the CAISO to ensure EO resources shown without exceeding deliverability limits at the POI have a MOO.

3. The Commission Should Work with Stakeholders to Develop a Framework Allowing for Validation that Deliverability Limits at the POI are Not Exceeded When the Co-Located Resource Has Multiple Offtakers

The Commission should work with stakeholders to develop a framework allowing for validation that deliverability limits at the POI are not exceeded when the co-located resource has multiple offtakers. When the same LSE contracts for both the generation and storage components, validating that the showing of both components does not exceed the deliverable MW at the POI is straightforward. However, when multiple offtakers contract for the same co-located resource (e.g., one LSE contracts for the generation component and another LSE contracts for the storage component), it can be difficult to ensure both components are shown in a manner that does not exceed the deliverable POI. The Commission should therefore work with stakeholders to develop a framework that can allow for easy validation that deliverability limits at the POI are not exceeded even if there are multiple offtakers.

Overall, significant benefits in RA affordability can be realized through finding solutions enabling EO resources to provide reliability value in the RA program. CalCCA therefore recommends the Commission reevaluate opportunities to allow EO co-located resources to count up to the deliverable POI.

IV. THE COMMISSION SHOULD INCORPORATE THE LOCAL RA CPE DATA REQUEST PROCESS INTO THE EXISTING RA FILING PROCESS RATHER THAN THE IRP DATA COLLECTION PROCESS

The Commission should incorporate the local RA CPE data request process into the existing RA filing process, rather than into the IRP data collection process. D.24-12-003 allows CPEs to receive information about local resources under contract so that CPEs can use the information to assess local area and sub-area needs.[19] This information will be collected from LSEs by Energy Division. The Scoping Ruling states, "[a] proposed decision, issued on October 29, 2024, stated that parties should submit proposals in Track 3 on how to synchronize the existing IRP data collection process with the data requirements adopted for the CPE framework in order to minimize duplication and administrative burden on Commission Staff."[20]

CalCCA supports minimizing duplication and the administrative burden associated with the many data reporting requirements within the RA and IRP programs. However, CalCCA has not identified how consolidating the local RA CPE data reporting requirements into the existing IRP reporting process minimizes duplication and administrative burden more than consolidating them within the existing RA reporting process. Therefore, absent a more comprehensive review of how to consolidate RA and IRP data reporting requirements, the Commission should house RA-related data requests within the RA program, and IRP-related data requests within the IRP program. To do so, the Commission should incorporate the local RA CPE data request process into an existing year-ahead or month-ahead filing within the RA program, rather than the IRP program.

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19 *See* D.24-12-003, *Decision on Track 2 Issues*, R.23-10-011 (Dec. 12, 2024), Ordering Paragraph 4: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M549/K295/549295013.PDF.

20 Scoping Ruling at 3.

V. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the proposals herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,

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

January 17, 2025

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

Order Instituting Rulemaking to Implement Senate Bill 520 and Address Other Matters Related to Provider of Last Resort.	R.21-03-011

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON THRESHOLD QUESTIONS**

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January 24, 2025

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SUMMARY OF RECOMMENDATIONS

In response to party opening comments, CalCCA recommends that the Commission:

- Consistent with SDG&E's recommendations: (1) issue a Decision with findings on the Phase 2 Threshold Questions to establish the core elements of a designated POLR framework; (2) issue the Threshold Questions Decision by the second quarter of 2025 in accordance with the Ruling's procedural schedule; and (3) defer consideration of the Ruling's more granular "Primary Topic Areas" until an IOU and non-IOU LSE submit notice to the Commission of their interest in transferring IOU POLR responsibilities to a Designated POLR;

- Reject arguments of PG&E, Cal Advocates, SDG&E, and SCE that the Commission's expanded jurisdiction over a Designated POLR extend beyond the POLR-specific services carved out in the unambiguous statutory language in California Public Utilities Code sections 216 and 387;

- Reject SDG&E's unjustified argument for expansive jurisdiction based on the non-IOU customer becoming "captive" to the Designated POLR;

- Reject SDG&E's and PG&E's unfounded concerns that a Designated POLR cannot offer separate POLR and non-POLR service;

- Reject recommendations of SDG&E, PG&E, and SCE for minimum core requirements for the Designated POLR that are not directly necessary to ensure that the Designated POLR can fulfill its narrow, statutorily prescribed service obligation;

- Reject SDG&E's argument that not more than one POLR can exist within a single IOU service territory; and

- Confirm that PG&E's concern that an existing POLR will not be fully relieved of its POLR obligations within the new, Designated POLR's territory is unfounded based on statute.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 520 and Address Other Matters Related to Provider of Last Resort.	R.21-03-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
REPLY COMMENTS ON THRESHOLD QUESTIONS

The California Community Choice Association[1] (CalCCA) submits these reply comments to the California Public Utilities Commission (Commission) on "Threshold Questions" pursuant to the October 24, 2024, *Assigned Commissioner's Phase 2 Scoping Memo and Ruling*[2] (Ruling), and in response to Opening Comments of San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), The Public Advocates Office at the California Public Utilities Commission (Cal Advocates), Shell Energy North America (US), L.P. (Shell Energy), and the Direct Access Customer Coalition, the Regents of the University of California, and Alliance for Retail Energy Markets (DA Parties).[3]

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[1] 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.

[2] *Assigned Commissioner's Phase 2 Scoping Memo and Ruling*, Rulemaking (R.) 21-03-011 (Oct. 24, 2024).

[3] All references to party Opening Comments are to the Opening Comments filed in this proceeding, R.21-03-011, on January 10, 2025.

I. INTRODUCTION

The Ruling identifies "Threshold Questions" to be addressed prior to delving into "Primary Topics" regarding the transfer of provider of last resort (POLR) responsibilities from investor-owned utilities (IOUs) to non-IOU load-serving entities (LSEs) (referred to herein as the Designated POLR). These Threshold Questions address three overall issues: (1) whether any IOUs or non-IOU LSEs are interested in the establishment of a Designated POLR; (2) the scope of Commission regulatory authority over the Designated POLR; and (3) the core qualifications for a Designated POLR.

In Opening Comments, no IOU or non-IOU LSE expressed *near-term* interest in transferring existing IOU POLR responsibility to a Designated POLR, but all parties addressed the issues of Commission regulatory authority and core qualifications for a Designated POLR. Given the lack of near-term interest, CalCCA supports SDG&E's recommendation at this time that the Commission issue a "Threshold Questions" Decision with findings framing a Designated POLR scheme to provide IOUs and non-IOU LSEs guidance in the event Designated POLR service is pursued in the future. CalCCA recommends that this Designated POLR scheme be crafted to limit Commission authority to the services prescribed by statute, *i.e.,* only the Designated POLR's *POLR-related services*.[4] In addition, the Commission should structure the core qualifications required of any prospective Designated POLR to *directly* ensure that the Designated POLR can fulfill its narrow, statutorily prescribed service obligation.

In response to party Opening Comments, CalCCA therefore recommends that the Commission:

- Consistent with SDG&E's recommendations: (1) issue a Decision with findings on the Phase 2 Threshold Questions to establish the core elements of a designated POLR

[4] Cal. Pub. Util. Code § 387(j).

framework; (2) issue the Threshold Questions Decision by the second quarter of 2025 in accordance with the Ruling's procedural schedule; and (3) defer consideration of the Ruling's more granular "Primary Topic Areas" until an IOU and non-IOU LSE submit notice to the Commission of their interest in transferring IOU POLR responsibilities to a Designated POLR;

- Reject arguments of PG&E, Cal Advocates, SDG&E, and SCE that the Commission's expanded jurisdiction over a Designated POLR extend beyond the POLR-specific services carved out in the unambiguous statutory language in Public Utilities Code sections 216 and 387;[5]

- Reject SDG&E's unjustified argument for expansive jurisdiction based on the non-IOU customer becoming "captive" to the Designated POLR;

- Reject SDG&E's and PG&E's unfounded concerns that a Designated POLR cannot offer separate POLR and non-POLR service;

- Reject recommendations of SDG&E, PG&E, and SCE for minimum core requirements for the Designated POLR that are not directly necessary to ensure that the Designated POLR can fulfill its narrow, statutorily prescribed service obligation;

- Reject SDG&E's argument that not more than one POLR can exist within a single IOU service territory; and

- Confirm that PG&E's concern that an existing POLR will not be fully relieved of its POLR obligations within the new, Designated POLR's territory is unfounded based on statute.

II. THE COMMISSION SHOULD ADOPT SDG&E'S RECOMMENDATION TO ISSUE FINDINGS ON THE THRESHOLD QUESTIONS TO ESTABLISH THE CORE ELEMENTS OF A DESIGNATED POLR FRAMEWORK REGARDLESS OF CURRENT INTEREST

The Commission should adopt SDG&E's recommendation to issue a Decision with findings on the Phase 2 Threshold Questions to establish the core elements of a designated POLR framework.[6] This Decision should be issued by the second quarter of 2025, in accordance with the

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

[6] *See* SDG&E Opening Comments*,* at 35. Note that other parties also recommend that consideration of the primary topic areas is premature given the lack of near-term interest in transferring POLR service to a Designated POLR. However, these parties did not recommend, as SDG&E did, a near-term Phase 2

timeframe set forth in the Ruling's procedural schedule.[7] The Commission should also defer consideration of the Ruling's more granular Primary Topic Areas until there is cause to do so – *i.e.,* parties' express interest in transferring POLR service to a Designated POLR. By establishing the core elements of the Designated POLR framework and directing that the Commission will consider the Primary Topic Areas when parties wish to move forward with the transfer of POLR responsibilities, the Commission will satisfy its obligations under section 387.

As CalCCA noted in Opening Comments,[8] section 387 mandates that the Commission develop a Designated POLR framework, regardless of interest in that framework from existing POLRs or prospective Designated POLRs.[9] In pursuit of that statutory mandate, the Commission should address the core elements of the Designated POLR framework now, even if there is no or limited interest in transferring POLR obligations from an existing POLR to a Designated POLR. Specifically, the Commission should address the nature of its regulatory authority over a Designated POLR and the ability of a Designated POLR to secure cost recovery for the cost of operating as POLR. In doing so, the Commission will faithfully comply with section 387 and will also give LSEs a sense of what to expect for these key threshold issues if or when interest develops in Designated POLR service. Indeed, by providing clarity regarding the nature of the Commission's authority over a Designated POLR—and confirming that it extends no further than

Decision on the threshold questions. *See, e.g.*, DA Parties Opening Comments, at 3, 10; PG&E Opening Comments, at 14-15; Cal Advocates Opening Comments, at 11.

7 Ruling, at 14.

8 CalCCA Opening Comments, at 3-4.

9 *See* Cal. Pub. Util. Code § 387(d) ("The commission shall develop a process to facilitate a joint application from load-serving entities that are not electrical corporations to request to transfer the responsibilities of the provider of last resort."); *id.* § 387(f) (the Commission "shall develop additional threshold attributes for a[n LSE] other than an electrical corporation to serve as provider of last resort to retail end-use customers in California").

a Designated POLR's POLR-specific services—the Commission may well shape interest in the Designated POLR framework, even if that interest is limited now.

CalCCA agrees with SDG&E and other parties recommending that the Commission stop short of building out the entirety of the Designated POLR framework and addressing the Primary Topic Areas given the current lack of interest in Designated POLR service. While section 387 mandates the development of the Designated POLR Framework, it doesn't provide a deadline by which the Commission must do so. Given that, CalCCA agrees that the Commission should conserve its limited resources and refrain from going further than resolving the core aspects of the Designated POLR framework. Instead, the Commission should rule that if an existing POLR and a prospective Designated POLR become interested in transferring POLR obligations to the prospective Designated POLR, the two LSEs should submit notice to the Commission of that interest through a Tier 1 Advice Letter. In turn, as SDG&E suggested, the Commission should then re-open this proceeding to fully address the Primary Topic Areas in the context of that concrete expression of interest.[10] After addressing those Primary Topic Areas, the interested parties would then submit their joint application consistent with section 387.

This method of developing the details of the Designated POLR framework will comply with the requirements of section 387, and also ensure the Commission is not building the Designated POLR framework only in the abstract. As Cal Advocates explained, without a demonstration of interest, efforts to fully establish the Designated POLR framework without clear interest will necessarily rely on assumptions that could prove irrelevant or become outdated.[11] Cal Advocates also rightly warns that building out the Designated POLR framework "prematurely"

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[10] SDG&E Opening Comments, at 35.
[11] Cal Advocates Opening Comments, at 11-12.

could "also risk creating unreasonable barriers or rules for any future transfer of POLR responsibilities."[12] The Commission should avoid these pitfalls.

The scope of the Commission's jurisdiction over a Designated POLR and a Designated POLR's ability to secure cost recovery for its POLR service are the central threshold questions this Commission should address. The Commission should address these key issues now, and adopt SDG&E's recommendation to defer consideration of the more granular elements of the Designated POLR Framework until two LSEs (one existing POLR and one prospective Designated POLR) submit a firm expression of interest in the transfer of POLR service to the prospective Designated POLR.

III. PARTY RECOMMENDATIONS TO BROADEN THE COMMISSION'S AUTHORITY OVER A DESIGNATED POLR SHOULD BE REJECTED BASED ON THE PLAIN LANGUAGE OF SECTIONS 216 AND 387

The Commission should reject arguments of PG&E, Cal Advocates, SDG&E, and SCE regarding the necessity of broad jurisdictional Commission authority over a Designated POLR. There is no dispute that sections 216 and 387 grant the Commission a degree of expanded regulatory authority over an LSE that becomes a Designated POLR. But that expanded authority is limited by those provisions' express and unambiguous statutory language. As set forth below, the Commission should: (1) reject party arguments regarding Commission jurisdiction outside of a Designated POLR's *POLR-specific services*; (2) reject SDG&E's argument for an expansive view of Commission jurisdiction based on a non-IOU customer becoming "captive" to the non-IOU; and (3) reject SDG&E's and PG&E's arguments that a Designated POLR cannot offer separate and distinct non-POLR services that the Commission does not regulate.

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12 *Id.* at 12.

A. Recommendations of PG&E, Cal Advocates, SDG&E, and SCE to Expand Commission Jurisdiction Beyond the Statutory Requirement of a Designated POLR's POLR-Specific Services Should be Rejected

PG&E's, Cal Advocates', SDG&E's, and SCE's arguments that the Commission's jurisdiction over a Designated POLR should extend beyond the POLR-specific services should be rejected based on the express and unambiguous statutory language in sections 216 and 387. Section 387(j) states that the Commission has authority to regulate a Designated POLR "as a public utility."[13] However, the Commission can only do so "***for the services provided by the provider of last resort pursuant to this article to ensure the provision of electrical service to customers without disruption if a load-serving entity fails to provide, or denies, service to any retail end-use customer in California for any reason***."[14] Section 216(a)(2) is similar, stating that a Designated POLR "is a public utility subject to the jurisdiction, control, and regulation of the commission and the provisions of this part ***regarding providing that service***."[15] In other words, the Commission is authorized to exercise a degree of regulatory supervision over a non-IOU LSE taking on POLR responsibilities, but the Commission's authority is ***limited to that LSE's POLR-specific services***.

The Commission must give meaning to these explicit statutory limitations when structuring the Designated POLR framework.[16] Had the Legislature not intended the emphasized language to be a limitation on Commission authority, there would be no reason to include it at all in section 387(j), or in section 216(a)(2). Instead, the Legislature could have simply directed that once an entity becomes a Designated POLR, the Commission has authority to regulate that entity as a

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13 Cal. Pub. Util. Code § 387(j).

14 *Id.* (emphasis added).

15 *Id.* § 216(a)(2) (emphasis added).

16 *See, e.g.*, *Tuolumne Jobs & Small Bus. Alliance v. Superior Court*, 330 P.3d 912, 1038 (Cal. 2014) ("It is a maxim of statutory interpretation that courts should give meaning to every word of a statute and should avoid constructions that would render any word or provision surplusage.").

"public utility." That broader regulatory authority would necessarily include the ability to supervise the Designated POLR's POLR-specific services. So, to give meaning to ***all of section 387(j)*** and ***all of section 216(a)(2)***, as California law requires, the Commission must recognize that its ability to regulate a Designated POLR is limited.

Some parties submitting comments in this proceeding acknowledge this limitation in California law. Shell Energy and the DA Parties correctly note that section 387 curtails the Commission's regulatory authority over a Designated POLR.[17] And even SCE concedes that section 387 does not require Commission regulation of anything more than a Designated POLR's POLR-specific services.[18]

In contrast, none of the parties that argue for expansive Commission regulation over a Designated POLR meaningfully address the express language of sections 387 and 216. PG&E concludes with limited discussion that the Commission should exercise regulatory authority over more than just a Designated POLR's POLR-specific service.[19] At best, PG&E argues that is the case "because it is unclear whether a non-IOU LSE serving as POLR can adequately separate its LSE-related procurement and ratemaking activity from its POLR responsibilities[.]"[20] But that argument takes a simplistic view of a Designated POLR's ability to provide a separate POLR-specific service.[21] PG&E's argument that such lack of clarity should necessitate expansive regulatory authority is also premature given the Commission has not yet fully explored the potential regulatory framework for a non-IOU LSE serving as POLR. And, more importantly, it

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17 Shell Energy Opening Comments, at 2-3; DA Parties Opening Comments, at 4-6.

18 SCE Opening comments, at 14 ("Alternatively, this provision can be read to confer broad authority on the Commission to regulate ***a non-IOU's POLR service*** as a public utility service, but not its other services (e.g., CCA or DA services) because those other services are not provided by the non-IOU in its POLR capacity.") (emphasis added).

19 *See* PG&E Opening Comments, at 7-10.

20 *Id.* at 8-9.

21 *See* Section III.C., *infra*.

says nothing about the statutory text of sections 216 and 387, which must guide this Commission's work in developing a Designated POLR Framework.

Cal Advocates similarly minimizes the express statutory limitations on the Commission's regulatory authority. Rather than confront those limitations head on, Cal Advocates argues that the Commission's authority is expansive because section 387(j) grants the Commission authority to "do all things that are necessary and convenient in the exercise of this power."[22] But this clause of section 387 is self-referential. It does not empower the Commission to exercise anything beyond the authority to regulate a Designated POLR "***for the services provided by the provider of last resort pursuant to this article to ensure the provision of electrical service to customers without disruption if a load-serving entity fails to provide, or denies, service to any retail end-use customer in California for any reason***."[23] In other words, when exercising the ***limited*** regulatory oversight over POLR service, the Commission can do all things necessary and convenient. Any other, more expansive interpretation would again render the limiting language in section 387 mere surplusage, which California law does not permit.[24]

SDG&E's arguments fare no better. Indeed, SDG&E's first argument in favor of broad Commission regulation over a Designated POLR is made in conclusory fashion, with SDG&E stating without support that once an LSE becomes a Designated POLR it becomes subject to the Commission's "plenary jurisdiction under Section 701."[25] But nowhere does SDG&E wrestle with the limiting language in section 387, which establishes that a Designated POLR becomes a public

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22 Cal Advocates Opening Comments, at 2-4.
23 Cal. Pub. Util. Code § 387(j).
24 *See, e.g.*, *Tuolumne Jobs & Small Bus. Alliance*, 330 P.3d at 1038.
25 SDG&E Opening Comments, at 11-12.

utility only for the purpose of providing service to customers whose LSE failed to provide them service.[26]

SDG&E then pivots to a discussion of the legislative history of section 387.[27] This discussion is unnecessary. When statutory language is clear and unambiguous there is no basis to consider legislative history.[28] Nowhere does SDG&E—or any other party—claim that sections 216(a)(2) or 387 are ambiguous. As such, consideration of the legislative history of Senate Bill (SB) 520 is inappropriate. Even if a discussion of legislative history was appropriate, the bill analysis referenced by SDG&E explicitly recognizes that SB 520 "[r]equires the CPUC to supervise and regulate each POLR, as necessary, as a public utility for the services *it provides as a POLR*."[29]

Finally, despite recognizing that section 387 does not require full, IOU-style regulation over a Designated POLR,[30] SCE suggests that the Commission could still reach beyond a Designated POLR's POLR-specific services "if doing so is cognate and germane to the Commission's regulation of the non-IOU's POLR service[.]"[31] Not so. SCE is correct that in *PG&E Corp. v. Pub. Util. Comm'n*, the California Court of Appeals affirmed Commission regulatory oversight of the non-public-utility holding companies of California's three large

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26 Cal. Pub. Util. Code § 387(j).

27 SDG&E Opening Comments, at 11-12.

28 *Cal. State. Univ., Fresno Ass'n, Inc. v. Cty. Of Fresno*, 9 Cal. App. 5th 250, 266 (Cal. App. 2017); *see also*D. 17-06-026, *Decision Revising Compliance Requirements for the California Renewables Portfolio Standard in Accordance with Senate Bill 350,* R.15-02-020 (June 29, 2017), at 5-6 (noting that California courts have dictated that unambiguous statutory language controls the Commission's interpretations of California law).

29 Senate Rules Committee Office of Senate Floor Analyses, SB 520 Analysis, at 3 (Sept. 10, 2019) (emphasis added).

30 SCE Opening Comments, at 14 ("Alternatively, this provision can be read to confer broad authority on the Commission to regulate ***a non-IOU's POLR service*** as a public utility service, but not its other services (e.g., CCA or DA services) because those other services are not provided by the non-IOU in its POLR capacity.") (emphasis added).

31 *Id.* at 14-15.

IOUs.[32] But that precedent is of little use here since the court's decision in *PG&E Corp.* turned on the fact that the Commission sought to exercise its authority over the holding companies only to enforce on the holding companies the preconditions to their very formation.[33] The court stated explicitly that the Commission in that case did "not seek to exercise general regulatory control over the holding companies as if they were public utilities[.]"[34]

Non-IOU LSEs like community choice aggregators (CCA) are in fundamentally different positions than the holding companies at issue in *PG&E Corp.* Unlike those holding companies, there are no preconditions on the creation of a CCA at issue here that would allow for the Commission to reach beyond the limited regulatory authority granted to the Commission under section 387 if a CCA becomes a Designated POLR, even if doing so was "cognate and germane" to the regulation of a public utility. Indeed, exercising authority over a CCA's non-POLR services would run afoul of the State's long-standing approach to CCA regulation, where the bulk of CCA operations are governed by publicly accountable local officials, and where CCAs are subject to open meeting, public record, and conflict of interest laws. As such, *PG&E Corp.*—and by extension section 701—does not provide the Commission with an expanded base of regulatory authority beyond the explicit grant of limited authority under section 387.

The Commission should look to the statutory text of SB 520 and find that its authority over a non-IOU Designated POLR extends only to that Designated POLR's *POLR-specific services*. At the same time, the Commission should reject the recommendations of PG&E, Cal Advocates, SDG&E, and SCE to broaden Commission authority beyond the express and unambiguous statutory language.

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32 *PG&E Corp. v. Pub. Util. Comm'n*, 118 Cal. App. 4th 1174, 1198-99 (Cal. App. 2004).
33 *Id.* at 1201.
34 *Ibid*.

B. SDG&E's Unjustified Argument for Expansive Jurisdiction Based on the Non-IOU Customers Becoming "Captive" Should be Rejected

Leaving the statutory text of sections 387 and 216(a)(2) behind, SDG&E argues for an expansive view of Commission authority over a Designated POLR because, in its view, once a non-IOU becomes POLR, the non-IOU's customers become "captive."[35] SDG&E argues that this means that there can be no separation between a Designated POLR's POLR-specific services and its non-POLR services. The consequence of this argument is a conclusion that SB 520—if operationalized—ends the limited customer choice Californians now enjoy. But that is not the case. The Commission should disregard SDG&E's policy-based arguments favoring expansive Commission regulation—even if the explicit statutory language of section 387 permitted such expansive regulation (which it does not).

The heart of SDG&E's policy-based arguments is its contention that when a non-IOU becomes a Designated POLR, its customers will find that the non-IOU's "existing retail service" is now their "***only*** electric generation service" option such that they are now "captive" to that non-IOU.[36] SDG&E never explains why that is the case, and the flaws of SDG&E's argument become clear when weighed against the limited scope of POLR service under section 387. Section 387 defines the POLR as the LSE that must "provide electrical service to any retail customer whose service is transferred to the designated [LSE] because the customer's [LSE] failed to provide, or denied, service to the customer or otherwise failed to meet its obligations."[37] In other words, California law makes clear the POLR is obligated to serve load only insofar as that load is returned to it on an ***involuntary basis***.[38] By taking on the POLR role, an LSE does not become the sole

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35 SDG&E Opening Comments at 3-7, 26-27.
36 *Id.* at 5 (emphasis added).
37 Cal. Pub. Util. Code § 387(a)(3).
38 *Ibid*.

provider in a given service territory, nor does it become the default provider in that given service territory. Nor is POLR service, as SDG&E contends, "the retail electric service offered by the non-IOU POLR to customers who have no other service option[.]"[39] POLR service is as section 387(a)(3) defines it: the obligation to provide service to customers where their original LSE failed to provide them service.

There are myriad ways in which Designated POLR service could play out, but—contrary to SDG&E's contention—approving a non-IOU LSE as a Designated POLR does not render that LSE's customers captive. For instance, if a non-IOU LSE becomes a Designated POLR for the entirety of an IOU's service territory, it will be obligated to serve all customers who return to it if their existing LSE fails to provide them with service. But under current law, the IOU in that service territory will remain, and its duty to serve customers that ***voluntarily*** elect IOU service under section 451 will remain, too. Further, customers of the non-IOU LSE that becomes the Designated POLR could have the option to depart from the non-IOU LSE to a direct access provider. In either case, the customers of the non-IOU LSE that became a Designated POLR do not become captive simply because the non-IOU LSE became a Designated POLR.

The risk of customers becoming "captive" to their non-IOU LSE that is Designated as a POLR is even more limited if the non-IOU becomes POLR for only a portion of an IOU's service territory, an arrangement section 387(c) expressly permits.[40] In that arrangement, the existing IOU would clearly continue to operate and serve load throughout the entirety of its service territory and would provide a clear option for customers of the non-IOU LSE to voluntarily choose if they deemed appropriate. All that would change is that the non-IOU LSE designated as POLR would

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[39] SDG&E Opening Comments, at 26.

[40] Cal. Pub. Util. Code § 387(c) ("The application may request a transfer of the responsibilities of the provider of last resort for the entire service territory of the electrical corporation ***or for a portion of that service territory***") (emphasis added).

stand ready to serve involuntarily returned load for a portion of the IOU's service territory. This would be the case such that if another non-IOU LSE (like a DA provider) failed, or if the IOU failed (a result that is unlikely) within that territory, its load would transfer to the Designated POLR. Once again, nothing about the Designated POLR in this scenario would render its existing customers "captive."

In the absence of any such "captive" customers, most of SDG&E's policy arguments in favor of expansive Commission jurisdiction fall away. But even if some customers did end up captive due to the designation of their non-IOU LSE as a Designated POLR, it still would not justify full Commission jurisdiction because non-IOUs, like CCAs, are fundamentally different than profit-motivated entities like existing IOUs. Commission oversight is rightly heightened when customers are held captive by a monopoly company with profit motives. The same concerns are not present when the LSE—like a CCA—is publicly accountable, has no profit motive, and has existing obligations to set rates in public, conduct its meetings in public, and allow for public participation. Indeed, that public agency accountability is analogous to—and displaces the need for—the Commission's review of CCA rates and services. So even if a customer does somehow become captive by virtue of its existing LSE becoming a "Designated POLR"—again, which is unlikely—that "captive" customer will be subject to the decisions of a public agency accountable to the public. These critical distinctions further eliminate SDG&E's justifications for expansive Commission jurisdiction.

C. SDG&E's and PG&E's Unfounded Arguments That a Designated POLR Cannot Offer Separate POLR and Non-POLR Services Should be Rejected

SDG&E's and PG&E's arguments against the possibility that a Designated POLR can offer separate and distinct non-POLR, and non-Commission regulated, services should be rejected. Once again, these arguments have no statutory basis. Section 387 defines POLR service narrowly to ensure that involuntarily returned customers are provided service from the Designated POLR.[41] Section 387 similarly defines the Commission's jurisdiction narrowly to allow for "public utility" style regulation over a Designated POLR's *POLR-specific services* only.[42] While there may be some practical challenges with developing separate POLR-specific services for a Designated POLR, the Commission can and should deal with them in the context of a joint application for Designated POLR service, not in the abstract in response to these Threshold Questions. Regardless of where the Commission deals with those issues, the Commission should acknowledge that nowhere does California law require that once an LSE becomes a Designated POLR its existing, non-POLR-specific services collapse into its POLR offerings.

Even SCE acknowledges this fact, explaining that it would be possible for a Designated POLR to offer separate POLR and non-POLR services.[43] This separation between POLR and non-POLR offerings could unfold in several ways. The Designated POLR, as SCE explains,[44] could operate each service with a separate procurement portfolio, with separate POLR and non-POLR rates. In this arrangement, the Commission could protect against cost-shifting between the non-POLR and POLR services by reviewing just the POLR rates to ensure that they are just and reasonable, as Cal. Pub. Util. Code section 451 requires.

Alternatively, the Designated POLR could elect to operate with a single procurement portfolio intended to serve both POLR and non-POLR customers. However, the Designated POLR could elect to charge any ***incremental costs*** associated with procurement to serve involuntarily returned load to those customers. In this second scenario, the Commission would once again have regulatory oversight over the Designated POLR's *POLR-specific rates* to ensure they are just and

41 *Id.* § 387(a)(3).
42 *Id.* § 387(j).
43 *See* SCE Opening Comments, at 4-7.
44 *Id.* at 6.

reasonable. And by exercising oversight over the POLR-specific rates, the Commission will be able to ensure that POLR customers are not subsidizing non-POLR customers.

Finally, a Designated POLR could also consider establishing a separate, POLR-specific entity that provides POLR services entirely separate from the affiliated entity's non-POLR offerings. In this scenario, and indeed in each of the other two scenarios, the Commission would have regulatory oversight over the rates the Designated POLR charges for POLR service. The Commission would be able to ensure that the rates are non-discriminatory, such that the Designated POLR provides service to all customers who suffer an LSE failure regardless of their customer class (and even if the Designated POLR does not provide non-POLR service to all customer classes[45]). And the Commission would be able to ensure that the rates for POLR service are just and reasonable. Section 387—which defines the scope of POLR service and the Commission's authority over that service narrowly—requires nothing more.

As SCE acknowledges, there are feasible avenues through which a Designated POLR can elect to offer distinct POLR and non-POLR services. Nothing in California law forecloses that ability and the Commission will fulfill its regulatory role under sections 216(a)(2) and 387 by regulating the POLR-specific services of a Designated POLR only. As a result, SDG&E's and PG&E's arguments should be rejected.

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[45] SDG&E suggests that if an LSE becomes a Designated POLR, it must provide all of its services to all customers, universally. *See* SDG&E Opening Comments, at 17. SDG&E again glosses over the limited nature of POLR service under California law. While a Designated POLR would be obligated to provide ***POLR-specific services*** universally, across customer classes, Cal. Pub. Util. Code § 387(c)(7) (emphasis added), that does not mean that a Designated POLR would be barred from providing non-POLR services to only specific customer classes.

IV. THE COMMISSION SHOULD REJECT SDG&E'S, PG&E'S, AND SCE'S RECOMMENDATIONS FOR UNNECESSARY CORE QUALIFICATION REQUIREMENTS FOR THE DESIGNATED POLR

The Commission should structure the core qualifications required of any prospective Designated POLR to *directly* ensure that the Designated POLR can fulfill its narrow, statutorily prescribed service obligation. Additional requirements suggested by parties including SDG&E, PG&E, and SCE are unnecessary to fulfill this obligation.

The surest way to meet this standard is to ensure that a prospective Designated POLR has sufficient liquidity, can borrow funds as necessary, and has a history of satisfying state procurement obligations to a reasonable degree. There appears to be broad agreement regarding at least some of these criteria. CalCCA proposes in opening comments that the Commission can ensure that a prospective Designated POLR will fulfill its obligation to serve involuntarily returned load by requiring that the prospective Designated POLR: (1) maintains 45 Days Liquidity on Hand (DLOH) to procure energy for one month; (2) has an investment grade (IG) credit rating; and (3) materially meets state-mandated procurement requirements for 12 months prior to submission of the joint application.[46]

Requiring additional levels of liquidity as proposed by SDG&E, PG&E, and SCE—whether by pricing energy at "stressed" prices or contemplating the simultaneous failure of all LSEs within a prospective Designated POLR's POLR-service area47—should be rejected. Not only would the simultaneous failure of multiple LSEs within a single Designated POLR service area be largely unprecedented, requests for expanded financial criteria ignore the existence of the Financial Security Requirement (FSR). As the Commission is aware, the FSR—which in the case

46 *See* CalCCA Opening Comments, at 16.

47 *See, e.g.*, SDG&E Opening Comments, at 28-29; PG&E Opening Comments, at 11; SCE Opening Comments, at 16-18.

of a Designated POLR would be posted by the other LSEs protected by that Designated POLR—is set aside to provide a backstop to ensure that the POLR can serve involuntarily returned load. In other words, the FSR is the first line of defense that ensures that the POLR can fulfill its core POLR obligation—not the POLR's liquidity. The liquidity level and IG credit rating CalCCA proposes goes above and beyond that first line of defense to provide yet further protection against the possible failure of a Designated POLR's ability to serve involuntarily returned load.

The Commission should also refrain from requiring ongoing financial monitoring of a Designated POLR since that effort would be largely duplicative of the Tier 2 financial reporting metrics the Commission established in Phase I of this proceeding. In other words, if a Designated POLR begins to suffer financial distress, the Commission will learn of it through those early warning, Tier 2 reporting obligations, and duplicative financial monitoring is unnecessary.

As PG&E acknowledges, each of the proposed obligations is ***stricter*** than what is required of existing IOU POLRs since the large IOUs are ***POLR by default*** and California law requires no specific liquidity or credit rating showing for the IOUs to maintain their roles as POLR.[48] Thus, in some regard, a Designated POLR will provide more stability to the California grid. Rather than simply assuming that the large IOUs can operate as POLR by default, the Commission can institute the above controls to ensure that Designated POLRs are properly equipped to serve a reasonable level of involuntarily returned load, just as section 387 requires. Therefore, any minimum requirements proposed by parties over and above what CalCCA proposed should be rejected.

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

V. THE COMMISSION SHOULD REJECT SDG&E'S ARGUMENT THAT MORE THAN ONE POLR CANNOT EXIST WITHIN A SINGLE IOU SERVICE TERRITORY

According to SDG&E, "[s]ection 387(e) makes clear that there can be only one POLR in a given service territory."[49] To the extent SDG&E makes this claim to state that there can be only one POLR in a given ***IOU service territory***—versus the claim that there is only one POLR in a given ***POLR service territory***—SDG&E is wrong.

In establishing the Designated POLR Framework, the Commission should make clear that California law expressly permits multiple POLRs within a single IOU service territory. Indeed, section 387(c) makes this plain, explaining that a joint application for Designated POLR service "may request a transfer of the responsibilities of the provider of last resort for the entire service territory of the electrical corporation ***or for a portion of that service territory***."[50] If a Designated POLR becomes POLR for only a portion of an IOU's service territory, the IOU will necessarily remain POLR for the remainder of its service territory.

This result is not contrary to section 387(e). Instead, section 387(e) adds that when another entity takes on POLR service, the prior POLR is freed from providing that same POLR service. So, if a Designated POLR only operates within a portion of an IOU's service territory, section 387(e) makes sure that the prior POLR is not liable to provide POLR service to the portion now served by the Designated POLR. But it does not free the prior POLR from continuing to provide POLR service to the remainder of the territory, and it does not bar the operation of two POLRs in a single territory, as SDG&E claims. Any other interpretation would lead to an unavoidable conflict with section 387(c) which, again, clearly contemplates the service of two POLRs in a single territory.

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49 SDG&E Opening Comments, at 3 (emphasis added).

50 Cal. Pub. Util. Code § 387(c) (emphasis added).

VI. THE COMMISSION SHOULD REJECT PG&E'S CONCERN THAT AN EXISTING POLR WILL NOT BE FULLY RELIEVED OF ITS POLR OBLIGATIONS WITHIN THE NEW, DESIGNATED POLR'S TERRITORY

PG&E generally opposes the concept of a Designated POLR Framework throughout its comments. Core to that opposition is PG&E's concern that even if a Designated POLR enters the marketplace, PG&E will remain on the hook to provide ultimate POLR services if or when the Designated POLR exits the market.[51] While PG&E's concern makes sense in theory, the statutory language of section 387 makes clear that it will not be a risk in practice.

Section 387(e) clarifies that an existing POLR is freed of its obligation to operate as POLR in all or a portion of its service territory if another entity becomes a Designated POLR for those portions of the existing POLR's service territory. The Commission should confirm that this statutory provision does not permit a reversion to the original POLR if the Designated POLR fails ***unless*** that reversion is triggered by the joint application section 387 requires to transfer POLR obligations.

As noted above, section 387(e) provides that an existing POLR is relieved of its POLR obligations so long as another entity is serving as a Designated POLR. PG&E interprets this statutory language to suggest that it will lose the protection of 387(e) if the Designated POLR goes under or simply elects to end its POLR service. But this conclusion ignores that section 387 establishes only one way for a POLR to end its operations as a POLR, and that is through a joint application to transfer POLR service to another entity.[52] Section 387(b) states that the POLR is either the large IOUs (by default), or another LSE if "it is designated by the Commission pursuant to [the application processes in] subdivision (c) or (d)."[53] Properly considered, this statutory

51 PG&E Opening Comments, at 1-6.
52 *See* Cal. Pub. Util. Code § 387(b).
53 *Ibid.*

language obviates PG&E's concern that it will somehow become the guarantor of a Designated POLR and that it will be required to operate on standby in case that Designated POLR fails. As SCE explains, "[a] POLR service provider—whether IOU or non-IOU—must truly be the ***provider of last resort*** for retail procurement in its service area" such that the "POLR does not have a backstop because ***it is the backstop*** procurement provider in its service territory."[54] SCE is correct, and the Commission should confirm this interpretation of section 387 in developing a Designated POLR Framework.

As is the case today for the incumbent IOU POLRs, a Designated POLR simply "cannot be allowed to fail."[55] The statutory regime acknowledges this by obligating the Commission to establish core financial and procurement criteria that a prospective Designated POLR must meet before becoming a Designated POLR. In other words, the statute recognizes that California's POLRs must not fail, and it entrusts the Commission with the necessary discretion to only approve Designated POLR service if it is convinced that the Designated POLR is situated to fulfill this fundamental obligation.

The Commission should respond to PG&E's concerns that it could remain liable as a secondary POLR even if another entity becomes a Designated POLR by confirming that once a Designated POLR takes on POLR service, the ***only method*** for relinquishing that new role is through a subsequent joint application to transfer that service to another LSE.

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[54] SCE Opening Comments, at 5 (emphasis added).
[55] *Id.*

VII. CONCLUSION

CalCCA respectfully requests that the Commission adopt the recommendations set forth herein.

Respectfully submitted,

/s/ Andrew Ball
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January 24, 2025

projects are required to sign a GIA and submit deposits without certainty of whether TPD is allocated. AES recommends the CAISO consider adjusting the GIA requirements in light of CAISO's unique TPD processes.

c.Opportunities to seek TPD: AES is not opposed to the three allocation opportunities starting with the TPD window opened after the interconnection facilities studies. AES supports the additional opportunity to seek TPD during the interconnection facility study, and the tariff should clearly note that opportunity is optional and does not remove one of the three attempts in seeking deliverability

[1]IPE Track 3B Straw Proposal, p. 12.

3. **Please provide your organization's questions or comments on the Adjusted 2nd Interconnection Financial Security Posting for Cluster 14 Parked Projects.**

   ?AES is highly supportive of CAISO's proposal to extend the second interconnection financial security posted for parked Cluster 14 projects to May 29, 2026. AES recommends the CAISO consider further adjusting the date if the 2025 TPD allocation results are delayed to ensure that developers have sufficient time to reconsider project viability before making the second posting.

4. **Please provide your organization's questions or comments on Special Consideration for Long Lead Time Generation and Storage Resources, specifically:**

   a) Eligibility b) Opportunity to defer first attempt to seek TPD c) Amount of TPD requested and reserved d) Triggers for releasing reserved TPD e) Need for additional detail and discussion

   AES has no comment at this time.

5. **Please provide any additional feedback:**

   ??AES seeks clarification on where TPD transfer is allowed for tech additions added through projects for FCDS-seeking resources. AES is opposed to additional restrictions on TPD transfer between queue clusters. At this time, CAISO proposes to only allow TPD transfer from Cluster 14 and earlier to Cluster 15; TPD transfers are prohibited from later queue clusters to earlier clusters. AES believes these are unnecessary additional restrictions because IPE Track 2 already added requirements for projects transferring TPD to either be withdrawn or demonstrate an EO PPA. Developers may have numerous reasons for transferring TPD from one project to another cluster to ensure project viability. AES believes that these are risks that the developers should consider and additional restrictions would not ensure that most commercially viable projects come online.

California Community Choice Association

SUBMITTED 01/29/2025, 03:19 PM

Contact
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1. **Please provide your organization's questions or comments on Intra-cluster Prioritization of Use of Existing SCD/RNU Headroom:**

   The California Community Choice Association (CalCCA) appreciates the opportunity to provide comments on the California Independent System Operator's (CAISO's) Track 3 Draft Final Proposal. CalCCA supports the CAISO's proposal to use its transmission plan deliverability (TPD) allocation process scoring methodology to allow generators to interconnect up to an amount that will not trigger the need for a long lead time (LLT) short circuit upgrade or other reliability network upgrades. This proposal will provide opportunities for projects to come online and obtain deliverability more quickly when there is headroom to do so, helping to alleviate the current interconnection capacity scarcity.

2. **Please provide your organization's questions or comments on the Modifications to the TPD Allocation Process, by these sections:**

   a) Allocation Groups b) Multi-fuel projects receiving an allocation with PPAs c) Parking d) Opportunities to seek TPD e) Eligibility of Energy Only projects to seek TPD f) Documentation g) Modifications to the TPD scoring criteria. H) Scoring for the Commercial Operation group

   The TPD allocation process is a critical part of project development because resources must obtain TPD to provide resource adequacy (RA). The CAISO proposes to redefine the TPD allocation groups as: (1) the power purchase agreement (PPA) group; (2) the commercial operation group; and (3) the conditional allocation group. The CAISO's proposal would provide projects with three consecutive opportunities to seek a TPD allocation and retain a conditional TPD allocation.

   For the PPA group, CalCCA supports the proposed requirement for offtakers to confirm active PPAs annually for projects within the PPA group to retain their deliverability allocations. This will help ensure PPAs are executed in good faith rather than with the intention of getting scored in the highest TPD allocation group and then canceling the PPA after receiving a TPD allocation. In addition, CalCCA supports categorizing projects within the PPA group based upon whether its PPA is with an offtaker that has an RA obligation. This will result in a meaningful differentiation of projects that meet versus exceed the minimum requirement, because it bases its ranking on RA obligations which drive the need for TPD. It will also provide for uniform treatment of all PPAs with load-serving entities.

For the commercial operation group, the CAISO proposes to include energy-only (EO) projects that go into commercial operation in clusters 14 and prior. Under the CAISO's IPE Phase 2, the CAISO developed and the Federal Energy Regulatory Commission (FERC) approved on September 30, 2024, CAISO Tariff Section KK, which states that "Interconnection Requests that proceed to the Cluster Study based on the criteria for Energy Only Interconnection Requests may not obtain Deliverability for that Generating Facility and any associated Generating Units thereafter, including without limitation through transfers, modifications, or the TP Deliverability allocation process."[1] CalCCA understands that the CAISO interprets this language to mean that projects in cluster 15 and later that seek to interconnect as EO cannot in the future seek TPD, even by submitting a new interconnection request once the resource reaches commercial operation.[2]

CalCCA understands and supports the CAISO's intent to prevent developers from utilizing the EO pathway to circumvent a competitive process for TPD allocation. However, there are legitimate reasons why projects may pursue interconnection via the EO process, such as, a willingness on the part of both developers and LSEs to contract for a period of time for EO deliveries. The CAISO should therefore not prevent EO projects from *ever* seeking deliverability. If a project enters the queue and comes online as EO, the project should be allowed to submit a *new* interconnection request and follow the intake and study process for obtaining deliverability.

This approach could help expand and expedite opportunities for developers to finance and construct projects without a TPD allocation while ensuring projects cannot circumvent the interconnection intake process, in which projects seeking deliverability and projects seeking EO are scored separately. Constructed and operational projects are more viable than earlier stage projects under development and should be allowed to compete against other projects in the interconnection intake process and TPD allocation process to contribute to the state's RA requirements. To avoid an EO resource from unduly benefitting from its EO status, the new interconnection queue request for deliverability should follow all of the criteria that the CAISO has developed. In doing so, demonstration of a PPA would need to include that it is for the capacity element of the resource and not the existing EO contract that it had previously signed. For these reasons, CalCCA proposes that projects that have achieved commercial operation as EO be allowed to submit new interconnection requests, apply for TPD allocation, and be scored along with all projects.

[1] *See* FERC Docket No. ER24-2671, *Order on Tariff Revisions* (Sept. 30, 2024), located at: https://www.caiso.com/documents/sep-30-2024-ferc-order-accepting-tariff-amendment-interconnection-process-enhancements-2023-er24-2671.pdf.

[2] It is not clear that FERC's intent was to *never* allow EO to later apply for and receive deliverability. FERC stated that "[f]inally, we decline to direct CAISO to clarify that an interconnection request that completes the interconnection study process and executes a GIA may change its status in a future cluster, without having to withdraw their initial interconnection position. . . We note that CAISO's Tariff does, however, permit expansions of generating facilities with [EO] deliverability status to receive deliverability if their interconnection requests proceed to the cluster study based on the criteria for interconnection requests seeking deliverability. *CAISO's Tariff also permits an interconnection customer to submit a new interconnection request for its generating facility if it seeks to be studied for deliverability in the future*." *Id.* at 214 (footnotes omitted) (emphasis added).

3. Please provide your organization's questions or comments on the Adjusted 2nd Interconnection Financial Security Posting for Cluster 14 Parked Projects.

CalCCA has no comments at this time.

4. Please provide your organization's questions or comments on Special Consideration for Long Lead Time Generation and Storage Resources, specifically:

a) Eligibility b) Opportunity to defer first attempt to seek TPD c) Amount of TPD requested and reserved d) Triggers for releasing reserved TPD e) Need for additional detail and discussion

CalCCA agrees with the CAISO that TPD will need to be allocated to LLT resources such as offshore wind, out-of-state wind, and geothermal, which currently have longer project development cycles, and that the timelines for development of these resources may not be compatible with the updated TPD allocation process outlined in Section 2 of these comments. The CAISO's draft final proposal for allowing eligible resources an extension to seek TPD allocations could provide a reasonable path forward for ensuring these resources can compete for TPD when they are commercially ready. The CAISO and the California Public Utilities Commission should take care to not oversize TPD reservations for LLT resources such that other technologies are unable to obtain TPD even when commercially viable and able to support system portfolio needs. In other words, the CAISO should not reserve TPD in excess of the amount of TPD specifically resulting from an upgrade triggered by eligible LLT resources in LRA portfolios. This is necessary so that other non-LLT resources can utilize the TPD resulting from *their* inclusion in LRA portfolios without being held up by the TPD reservation process. The CAISO should also specify that this process is not specific to a certain procurement entity but applies generally to all procurement entities seeking to develop LLT resources. Moreover, the CAISO should confirm that once within the 3-year window for seeking deliverability LLT resources would need to follow the standard process for TPD allocation (i.e. the process established for all resources).

In addition, the CAISO's proposal for releasing reserved TPD if specific LLT resources upon removal from the LRA portfolio or cancellation of their associated transmission upgrades is a crucial element of this proposal. Releasing unused TPD will be necessary to ensure, in the event LLT resources do not progress, projects that are ready for TPD allocations can obtain them.

5. **Please provide any additional feedback:**

   CalCCA has no additional feedback at this time.

California Public Utilities Commission - Energy Division

SUBMITTED 01/29/2025, 07:03 PM

Contact
David Withrow (David.Withrow@cpuc.ca.gov)

1. **Please provide your organization's questions or comments on Intra-cluster Prioritization of Use of Existing SCD/RNU Headroom:**

   CPUC Staff commends CAISO for developing this creative path to accelerate interconnection for projects that otherwise would remain waiting for a transmission upgrade by making use of available transmission headroom in the meantime.

   We support utilizing the TPD scoring system for this intra-cluster prioritization of a set of generation and storage resources that are dependent upon a Reliability Network Upgrade with an estimated construction time of more than four years. We note that the TPD scoring system awards the highest "points" for projects with an executed PPA or where the LSE demonstrates the capacity would be used to meet its RA obligation; thus, the scoring system largely reflects LSE preferences. CPUC Staff agrees this scoring system is appropriate for allocating scarce headroom.

   CPUC Staff suggests that CAISO consider retaining this process for future Clusters beyond Cluster 14, should headroom be available in areas where resources may be subject to a delayed transmission upgrade.

2. **Please provide your organization's questions or comments on the Modifications to the TPD Allocation Process, by these sections:**

   a) Allocation Groups b) Multi-fuel projects receiving an allocation with PPAs c) Parking d) Opportunities to seek TPD e) Eligibility of Energy Only projects to seek TPD f) Documentation g) Modifications to the TPD scoring criteria. H) Scoring for the Commercial Operation group

   CPUC Staff supports CAISO's proposed changes to simplify and reduce the number of groups and clarify the priorities for deliverability allocation. We believe this proposal allows reasonable opportunity for projects to seek deliverability in a timeframe that generally matches the expected commercial operation date of the project.

   CPUC Staff also support CAISO's proposal to allow no more than three opportunities for projects to receive a deliverability allocation, assuming that this entire Draft Final Proposal includes the reservation of deliverability for particular resource types identified by the CPUC and other local regulatory authorities.

3. **Please provide your organization's questions or comments on the Adjusted 2nd Interconnection Financial Security Posting for Cluster 14 Parked Projects.**

   CPUC Staff has no comments at this time.

4. **Please provide your organization's questions or comments on Special Consideration for Long Lead Time Generation and Storage Resources, specifically:**

   a) Eligibility b) Opportunity to defer first attempt to seek TPD c) Amount of TPD requested and reserved d) Triggers for releasing reserved TPD e) Need for additional detail and discussion

   CPUC Staff support this proposal to enable the reservation of capacity that can eventually enable the deliverability of particular "non-routine" or "long lead-time" resource types and amounts that are identified by the CPUC or Local Regulatory Authorities (LRAs).

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

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	R.20-05-003

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION TRANSMITTING ELECTRICITY RESOURCE PORTFOLIOS TO THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR FOR 2025-2026 TRANSMISSION PLANNING PROCESS

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January 30, 2025

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- Commit to using updated procurement data from LSEs for 2026-2027 TPP portfolio development to ensure the modeling inputs use the most up-to-date procurement plans considering new resource availability and cost information;

- Commit to evaluating future IRP portfolios against projected RA requirements to ensure the future resource mix satisfies RA needs under the SOD framework;

- Commit to collaborating with LSEs to inform and make progress on transmission needed to support OOS wind by determining how to map OOS resources to align expectations on the timing and size of policy-driven transmission projects that will expand MIC needed to deliver OOS resources to the CAISO BAA consistent with commercial interest; and

- Address interconnection queue intake in addition to TPD reservations to ensure a process for resources *seeking to enter* the queue supports a diverse set of technologies under the CAISO's IPE Track 2 policy.

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The California Community Choice Association[1] (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[2] on the proposed *Decision Transmitting Electricity Resource Portfolios to the California Independent System Operator for 2025-2026 Transmission Planning Process*[3] (Proposed Decision), mailed January 10, 2025.

[1] 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.

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

[3] Proposed *Decision Transmitting Electricity Resource Portfolios to The California Independent System Operator for 2025-2026 Transmission Planning Process*, (Rulemaking (R.) 20-05-003 (Jan. 10, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M553/K678/553678610.PDF.

I. INTRODUCTION

CalCCA appreciates the opportunity to comment on the Proposed Decision's electricity resource portfolios to be transmitted to the California Independent System Operator (CAISO) for the 2025-2026 Transmission Planning Process (TPP). Efforts of Commission staff to develop the portfolios are also appreciated. The Proposed Decision recommends the CAISO analyze two electricity portfolios: (1) a base case portfolio based upon a 25 million metric ton (MMT) greenhouse gas (GHG) emissions target; and (2) a sensitivity portfolio intended to help study the transmission need to support a portfolio with more long-lead time (LLT) resources than the base case portfolio. The Proposed Decision also asks the CAISO to "reserve" transmission plan deliverability (TPD) for certain geographically-limited LLT resources.

CalCCA generally supports the Proposed Decision's base case portfolio, as it continues progression towards the 25 MMT GHG target and maintains consistency with prior TPPs where possible. The Commission, however, must correct four errors in its final decision to ensure that: (1) future TPPs use the most up-to-date procurement information from LSEs to develop the new portfolios; (2) planned resources in Integrated Resource Plan (IRP) portfolios meet the planning years' projected Resource Adequacy (RA) requirements; (3) progress continues on transmission development to support out-of-state (OOS) resources with commercial viability; and (4) the interconnection queue includes a diverse set of technologies consistent with the planned portfolio resources. Specifically, the Commission errs in the Proposed Decision by failing to:

- Commit to using updated procurement data from load serving entities (LSEs) for 2026-2027 TPP portfolio development to ensure the modeling inputs use the most up-to-date procurement plans considering new resource availability and cost information;
- Commit to evaluating future IRP portfolios against projected RA requirements to ensure the future resource mix satisfies RA needs under the slice-of-day (SOD) framework;
- Commit to collaborating with LSEs to inform and make progress on transmission needed to support OOS wind by determining how to map OOS resources to align expectations on

the timing and size of policy-driven transmission projects that will expand maximum import capability (MIC) needed to deliver OOS resources to the CAISO balancing authority areas (BAA) consistent with commercial interest; and

- Address interconnection queue intake in addition to TPD reservations to ensure a process for resources *seeking to enter* the queue supports a diverse set of technologies under the CAISO's Interconnection Process Enhancements (IPE) Track 2 policy.

II. THE COMMISSION ERRS BY FAILING TO COMMIT TO USING UPDATED LSE PROCUREMENT DATA FOR THE 2026-2027 TPP PORTFOLIO DEVELOPMENT

The Commission errs by failing to commit in the Proposed Decision to using updated LSE procurement data for the 2026-2027 portfolio development. The Commission developed the Proposed Decision's 2025-2026 TPP portfolios using individual IRP plans from LSEs filed in November 2022.[4] The Commission notes in the Proposed Decision that some parties suggest it "reduce reliance on the individual IRP resources planned by LSEs, . . . for various purposes."[5] The Commission, however, "does not find it appropriate" to do so because:

> the plans represent a reasonable approximation of the resources that LSEs intend to procure. The timeframe for this analysis required using the November 2022 IRP plans, and we also note that using updated procurement data may have selectively eliminated some resource types, including OSW. For this TPP, we find that it is preferable to maintain consistency with prior TPP base cases.[6]

CalCCA agrees with the Commission that individual IRP plans represent a reasonable approximation of the resources LSEs plan to procure and that consistency with prior TPPs is a prudent objective. Individual IRP plans are an important input into the modeling and should continue to be used to develop the TPP portfolios. However, individual LSE plans are not static. As more information about resource availability and costs becomes known, LSE plans will evolve to reflect

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4 *See* Proposed Decision, at 2.
5 *Id.* at 24.
6 *Ibid.*

this new information. For this reason, the Proposed Decision errs in failing to commit to using updated LSE procurement information for the next TPP portfolio development for 2026-2027.

The Commission used LSEs' 2022 IRPs for both the 2024-2025 portfolios and for this Proposed Decision's 2025-2026 portfolios. LSEs will not update their IRPs again until November 1, 2025.[7] If the Commission follows the same schedule for the 2026-2027 portfolio development that it used for the 2025-2026 portfolio development,[8] then the Commission will need to rely again on LSEs' 2022 IRPs. The 2022 IRPs will be even more stale by this time. To ensure the 2026-2027 TPP portfolio uses current information (and does not incorporate outdated, four year old information), the Commission should commit to either: (1) using updated individual LSE IRPs filed in November 2025 if portfolio development occurs after individual LSE IRP plans are filed in November 2025; or (2) if portfolio development occurs before individual LSE IRP plans are filed in November 2025, supplementing the 2022 IRPs with updated procurement information from LSEs through semi-annual compliance filings or other existing procurement status reports. If the Commission uses updated procurement information provided by LSEs through existing procurement status reporting, the Commission can ask LSEs to validate the information to ensure all resources under contract are included.

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[7] *See Assigned Commissioner's Amended Scoping Memo and Ruling Extending Statutory Deadline*, R.20-05-003 (April 18, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M529/K525/529525977.PDF.

[8] The Commission issued a Ruling with recommended 2025-2026 TPP Portfolios in September 2024. *See Administrative Law Judge's Ruling Seeking Comments on Electricity Resource Portfolios for 2025-2026 Transmission Planning Process*, R.20-05-003 (Sept. 12, 2024): http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=539999211.

III. THE COMMISSION ERRS BY FAILING TO COMMIT TO EVALUATING FUTURE IRP PORTFOLIOS AGAINST PROJECTED RA REQUIREMENTS

The Commission errs in the Proposed Decision by failing to commit to evaluating future IRP portfolios against projected RA requirements. In Comments to the September 12, 2024, Ruling,[9] CalCCA recommended the Commission verify that the resources in the proposed base case meet projected SOD RA needs.[10] This recommendation was not intended to advocate for SOD as *the reliability metric* that should be used in RA and IRP programs. Instead, it intended to ensure planned resources in IRP portfolios meet the planning years' projected RA *compliance requirements*, in addition to the modeled reliability and GHG targets modeled in Renewable Energy Solutions Model (RESOLVE). The Proposed Decision responds to CalCCA's recommendation and the recommendations of other parties regarding alignment between RA SOD requirements and IRP portfolios by stating that it "expects that this issue will continue to be relevant in this proceeding (and/or its successor) as well as the [RA] rulemaking (R.23-10-011)." However, the Commission finds that "[i]t is beyond the scope of this proposed decision."[11]

The Commission errs by declining to establish in the Proposed Decision how and when it will address the interactions between RA and IRP.[12] The IRP program establishes the planned build out of capacity that must meet future compliance requirements, like the renewable portfolio standard requirements and RA requirements. Continuing to delay the process of better aligning IRP and RA

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[9] *See Administrative Law Judge's Ruling Seeking Comments on Electricity Resource Portfolios for 2025-2026 Transmission Planning Process*, R.20-05-003 (Sept. 12, 2024): http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=539999211.

[10] *See California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Electricity Resource Portfolios for 2025-2026 Transmission Planning Process*, R.20-05-003 (Sept. 30, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M541/K493/541493142.PDF.

[11] Proposed Decision, at 25.

[12] *Id.* In the RA proceeding, the Commission has also deferred coordinating the RA and IRP proceedings until after the Commission issues a decision on the Reliable and Clean Power Procurement Program (RCPPP). *See Administrative Law Judge's Ruling Deferring Track 2 Issue on Coordination with the Integrated Resource Planning Proceeding*, R.23-10-011 (June 4, 2024): http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M533/K099/533099060.PDF.

planning processes risks building a portfolio that does not provide sufficient capacity to meet system RA requirements, which are measured under the SOD framework. As observed in recent years, tight RA supply conditions can drive high RA prices, adversely affecting customer affordability.[13] The Commission can ensure sufficient energy and capacity to meet RA requirements by first developing the IRP portfolios as it does today using loss-of-load expectation modeling in Strategic Energy Risk Valuation Model (SERVM) and effective load carrying capability in RESOLVE. Then, the Commission can test that portfolio under SOD counting rules to ensure the two approaches produce similar levels of reliability and cost-effectiveness. If there is a discrepancy, the Commission should seek to reconcile the two approaches by analysis-driven adjustments to the SOD planning reserve margin or IRP modeling assumptions. The Commission should modify the Proposed Decision to commit to evaluating future IRP portfolios' ability to meet projected RA requirements starting with the next TPP cycle.

IV. THE COMMISSION SHOULD COMMIT TO COLLABORATING WITH LSES ON TRANSMISSION NEEDED TO SUPPORT OOS WIND

The Commission errs in the Proposed Decision by not committing to collaborate with LSEs on information regarding transmission needed to support OOS wind. The Proposed Decision's base case includes significantly more OOS wind than the previous year's base case.[14] If fully developed, these new amounts "will require additional transmission beyond those projects already

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[13] *See* California Public Utilities Commission Energy Division, *2022 Resource Adequacy Report* (May 2024), at 29: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2022-ra-report_05022024.pdf ("The weighted average price of system RA in September 2022 was $13.48, which represents a 357% increase over the September 2017 weighted average. The weighted average of August prices have increased by 295% since 2017 from $3.13 to $12.36/kW-month. The year-on-year increase in weighted average price between 2021 and 2022 was 56% for September and 53% for August. In contrast, January RA prices increased a more modest 113% between 2017 and 2022, from $2.52/kW-month to $5.87/kW-month. *These price increases are likely be driven by tight supply conditions attributed to resource retirements, load forecast increases, and changes in counting conventions that have reduced the RA value of certain resources.*" (emphasis added)).

[14] Proposed Decision, at 55: "last year's portfolio had 6 GW in 2034 and this year's has 9 GW in 2035."

approved and in development..."[15] The Proposed Decision highlights uncertainties associated with OOS wind, including not yet having interconnection requests from developers to inform optimal delivery points and the complexities associated with negotiating inter-regional lines with other balancing authorities.[16] Given these uncertainties, the Commission asks the CAISO in the Proposed Decision to study the transmission needed to support the additional OOS wind in the base case. The Commission, however, asks the CAISO not to trigger upgrades needed beyond the amounts that can be accommodated on the already-identified and in-development transmission upgrades in this TPP cycle.[17]

CalCCA appreciates that there are unique uncertainties and complexities associated with developing transmission infrastructure to support OOS wind. The Proposed Decision's recommendations would allow time to study potential routes and injection locations to get a better understanding of costs and confirm the need for the high level of OOS wind before committing to new upgrades. At the same time, the complexities associated with transmission development to support OOS resources support the Commission determining the path forward for OOS resources as soon as possible so that identified transmission projects can be developed in time to support the need. LSEs are exploring opportunities to contract with OOS resources and have valuable insights into locations that are most commercially attractive. The Commission should therefore modify the Proposed Decision to specifically state that it will engage with LSEs directly to ensure progress on identifying transmission projects to support OOS resources.

Specifically, LSE information can help determine how to map OOS resources to align expectations on the timing and size of policy-driven transmission projects that will expand MIC

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15 *Ibid.*
16 *Id.* at 56.
17 *Ibid.*

needed to deliver OOS resources to the CAISO BAA. The Commission should consult with LSEs during this special study process for OOS and within the busbar mapping process. LSEs should, with the help of their suppliers, be able to provide input to the Commission during the busbar mapping process to ensure their projects can import power through the interties identified by the Commission in its busbar mapping process. Allowing LSEs the opportunity to provide their input on OOS resource opportunities will help inform the study process by identifying potential locations that are most commercially viable.

Overall, the Commission should strive to develop meaningful portfolios that match load needs, resources, and transmission such that the variety of goals can be achieved (electrification and clean energy chief among them) affordably for all customers. Mismatches in timing can threaten reliability and affordability. The IRP and TPP are key elements in directing the development of resources and transmission in a timely and affordable manner. While current circumstances may warrant a delay in approving certain upgrades resulting from the amount of base case OOS wind, the Commission should ensure the next TPP's base case is actionable, and includes all necessary resource additions and locations that result in necessary transmission upgrades to support system needs.

V. THE COMMISSION ERRS BY FAILING TO ADDRESS INTERCONNECTION QUEUE INTAKE IN ADDITION TO TPD RESERVATIONS

The Commission highlights in the Proposed Decision that the mapped portfolios do not include resources that fully align with the CAISO interconnection queue resources.[18] For example, the Commission states that "there are more battery storage projects in the queue with [transmission plan deliverability (TPD)] than the total amount of battery storage in the 2040 portfolio."[19] The

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18 *See id.* at 51-52.
19 *Id.* at 52.

Commission cautions that, although storage can be sited with much fewer constraints than most other resources, if the CAISO does not reserve some deliverability for resources with longer lead times (like offshore wind (OSW)), deliverability could be allocated exclusively to storage in the queue.[20]

The Commission addresses this concern by asking the CAISO to "reserve" deliverability on the transmission system for geothermal, biomass, OSW, non-battery long-duration energy storage for the amounts in the 2035 portfolio, and some of the in-state/on-shore and out-of-state wind in the portfolio.[21] This request aligns with the CAISO's IPE Track 3 Draft Final Proposal, in which the CAISO proposes to provide special extensions for interconnection of certain LLT resources to seek deliverability allocations using input from local regulatory authorities on how to define LLT for this purpose.[22]

While the Proposed Decision addresses how LLT resources ***already in the queue*** should be treated to allocate deliverability, it fails to address the interconnection queue intake process for resources ***seeking to enter*** the queue to ensure a diverse set of technologies are able to enter the queue under the CAISO's IPE Track 2 policy.[23] Under the new framework, in which not all interconnection requests will be studied, the Commission's input into the CAISO's interconnection

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20 *Ibid.*

21 *Id.* at 54.

22 *See id.* at 53.

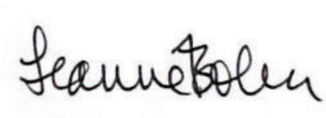
23 As part of its IPE Track 2, the CAISO will accept and study interconnection requests up to 150 percent of available and planned deliverability. It will determine which interconnection requests to study based on several scoring criteria. One scoring criterion is the LLT resource score within its "System Need" category. The CAISO will define LLT for the purposes of this scoring criterion as: "Meet[ing] the requirements of the [Commission's] resource portfolios where the TPP has approved transmission projects to provide necessary transmission requirements. Only [LLT] resources that are required to meet the [Commission's] resource portfolio requirements are eligible, including resource types that are considered for central procurement under Assembly Bill 1373 (2023), or as specifically identified by the [Commission] in the portfolios provided to the [CAISO] for use in the [TPP]." CAISO, *2023 Interconnection Process Enhancements Track Final Proposal* (Mar. 28, 2024), at 62: https://stakeholdercenter.caiso.com/InitiativeDocuments/FinalProposalInterconnectionProcessEnhancements2023Track2.pdf.

intake process is an important mechanism for ensuring an interconnection queue that is sufficiently aligned with resources in the TPP portfolios. For that reason, the Commission should modify the Proposed Decision to adopt CalCCA's recommendation to adopt a process used each TPP cycle to determine which resources cannot meet the resource portfolio levels with capacity already progressing through the interconnection queue.[24] The Commission should use this analysis to identify resources that should be classified as LLT for the purpose of the CAISO's IPE System Need score used to determine which projects will enter the queue.

VI. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and requests adoption of the recommendations proposed herein. For all the foregoing reasons, the Commission should modify the Proposed Decision as provided in Appendix A, attached hereto.

Respectfully submitted,



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[24] *See California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Electricity Resource Portfolios for 2025-2026 Transmission Planning Process*, R.20-05-003 (Sept. 30, 2024), at 12-13: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M541/K493/541493142.PDF.

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION TRANSMITTING ELECTRICITY RESOURCE PORTFOLIOS TO THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR FOR 2025-2026 TRANSMISSION PLANNING PROCESS

PROPOSED CHANGES TO FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDERING PARAGRAPHS

Proposed text additions show as **<u>bold and underlined</u>**
Proposed text deletions show as **~~bold and strikethrough~~**

FINDINGS OF FACT

1. With each annual TPP cycle, Commission staff make updates to inputs and assumptions, which can include resource cost assumptions, import assumptions, transmission constraints, **<u>updated LSE procurement information,</u>** and/or other updates.

12. OOS wind and Northeastern California in-state wind development will require development of complex new transmission outside of the CAISO, with cooperation from other regional entities, **<u>and coordination with LSEs to determine the most commercially viable projects</u>**.

<u>New: If the interconnection intake process does not identify which portfolio resources do not have sufficient MWs in the interconnection queue to support portfolio levels, resource interconnections may be inconsistent with planned portfolios.</u>

<u>New: If the IRP portfolios are not tested against projected RA requirements, planned resources may be insufficient to meet future RA compliance obligations.</u>

CONCLUSIONS OF LAW

13. It is reasonable to request that the CAISO not trigger the approval of significant new transmission to support Northeast California wind and OOS wind on new regional transmission lines this year, but rather study these options**<u>,</u>** **~~and~~** interface with regional partners, **<u>and seek input from LSEs</u>** in order to plan for future development of this transmission with a better understanding of routing options**<u>,</u>** **~~and~~** potential costs**<u>, and commercial viability</u>**.

<u>New: It is reasonable to identify which portfolio resources do not have sufficient MWs in the interconnection queue to support portfolio levels and ask the CAISO to classify these resources as LLT for the IPE System Need Score.</u>

<u>New: Commission staff should begin work on developing a test to ensure IRP portfolios meet projected RA requirements beginning with the 2026-2027 TPP cycle.</u>