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STATE OF CALIFORNIA
CALIFORNIA ENERGY COMMISSION

IN THE MATTER OF: *Preparation of the 2026 Integrated Energy Policy Report (IEPR) Update*	DOCKET NO. 26-IEPR-01 RE: Scoping Order

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE DRAFT SCOPING ORDER FOR THE 2026 INTEGRATED ENERGY POLICY REPORT UPDATE

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March 25, 2026

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STATE OF CALIFORNIA
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CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE DRAFT SCOPING ORDER FOR THE 2026 INTEGRATED ENERGY POLICY REPORT UPDATE

The California Community Choice Association[1] (CalCCA) submits these comments pursuant to the *Notice of Request for Comments on the Draft Scoping Order for the 2026 Integrated Energy Policy Report Update*[2] (Notice), dated March 10, 2026.

I. INTRODUCTION

The Draft Scoping Order for the 2026 Integrated Energy Policy Report Update (Scoping Order) puts forth the following scoping items for the 2026 Integrated Energy Policy Report (IEPR) Update: (1) California electricity demand forecast; (2) California geothermal resources; and (3) energy equity and environmental justice. CalCCA supports including these items in the

[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] *Notice of Request for Comments on the Draft Scoping Order for the 2026 Integrated Energy Policy Report Update*, 26-IEPR-01 (Mar. 10, 2026): https://efiling.energy.ca.gov/GetDocument.aspx?tn=268981&DocumentContentId=106175.

scope and appreciates the efforts of the California Energy Commission (Commission) to develop the IEPR each year, which serves as a foundational document for California's energy policy.

The scope of analysis undertaken by Commission staff to develop the IEPR is a significant undertaking under any scenario. Current fluctuating policy, technological, and market forces further complicate this difficult task. To ensure forecasted load growth reflects the best-known information at the time of forecast development, the Commission should seek information from all knowledgeable stakeholders to inform the likelihood and timing of large load interconnections. Community choice aggregators (CCAs) are well-positioned to evaluate new load growth given their unique access to information, either from large load customers or their local permitting agencies. Consulting with CCAs, along with the investor-owned utilities (IOU) and large load customers, will ensure information used to develop the forecast is as accurate as possible.

The Scoping Order indicates that the 2026 IEPR Update will include an assessment of the impacts from utility energization applications (known loads) data and discussion around how to include these loads in the forecast. Given known loads are inherently uncertain, to the extent the Commission considers including known loads in the forecast, the Commission should continue to exclude them from the Planning Forecast. Incorporating known loads is not necessary for the Planning Forecast given its intended purpose.

The Scoping Order also states that the Commission will explore challenges and opportunities for geothermal development in California. Geothermal resources have the potential to play a significant role in the State's clean energy transition by providing clean baseload energy. Despite interest from LSEs and regulators in geothermal procurement, the amount of geothermal projects in the interconnection queue does not reach the levels included in planning

portfolios. The Commission should therefore seek to identify and reduce barriers that may be preventing geothermal development to the levels assumed in planning.

In summary, CalCCA recommends the Commission:

- Solicit information on new loads from all informed stakeholders including CCAs to inform the likelihood and timing of large loads before including them in the forecast;
- Coordinate with the California Public Utilities Commission (CPUC) to adopt a formal process for allocating RA obligations for data center load based on actual interconnection information and milestones;
- To the extent the Commission considers including known loads as defined in the 2025 IEPR process in the demand forecast, continue to exclude them from the planning scenario; and
- Seek to identify and reduce barriers for geothermal development in and delivery to California.

II. INFORMATION ON NEW LOADS INCLUDED IN THE FORECAST SHOULD BE SOLICITED FROM ALL INFORMED STAKEHOLDERS BEFORE INCLUDING THEM IN THE FORECAST TO INFORM THE LIKELIHOOD AND TIMING OF LARGE LOADS

The Commission should capitalize on the knowledge and expertise of CCAs, along with other stakeholders, to verify the information received from IOUs regarding future loads, including data centers. CalCCA and its members appreciate the opportunities within the IEPR process to provide feedback to Commission staff and the openness of Commission staff to incorporate this feedback in its development of the Demand Forecast. CCAs can provide insight on and verification of future loads included in the proposed forecasts.

CCAs serve local communities and are well-positioned to evaluate new load growth given their unique access to information, either from large load customers or their local permitting agencies. Cities and counties have data on land use and building permits that can help inform the load forecast and each CCA's association with cities and counties will give it unique

access and insight into where new facilities are in their development and when they will be expected to be operational.

This insight is valuable, as information received by the IOUs is often insufficient to inform the IEPR Demand Forecast. For example, IOU energization dates alone are not a sufficient estimate as to when a project will come online, especially in the near term. Data centers with a 2027 energization date but have not started the permitting process would likely be delayed. In addition, energization requests to an IOU do not account for project feasibility. For example, in San Jose, assumed energization timing may be optimistic for data centers in the downtown area, which have additional permitting considerations. Additionally, as CCAs are community-based, CCA staff and local partners have the unique ability to personally observe the progress of any large load construction or build out. What is observed – and verified by local permitting status – may not align with IOU information. Lastly, actual usage of requested capacity may also differ by area, and a single assumption may not adequately reflect these differences. CalCCA urges the Commission to make ample use of the information community-based LSEs such as CCAs can provide.

To ensure all informed parties can provide insight into and verification of proposed forecasts, the Commission should strive to make as much data public as possible before it is relied upon in the IEPR Demand Forecast. Historically, it has not been possible for CCAs and data center customers to validate the information provided by the IOUs before it is used in the IEPR because it is submitted confidentially. CCAs have observed that once they do receive the data, it is often duplicative and/or contains errors. For example, upon notification that five of eight interconnection applications in a CCA service area were expected to be data centers, one

CCA's investigation found that of the five data center applications, three were not in their service area and two were scaled down to smaller, non-data center loads.

The CEC should therefore either require the data be shared with CCAs or request information from both IOUs and CCAs and validate the information for consistency. Given reliability and cost implications of forecasting new loads, ensuring all informed stakeholders can review the data before it is used in the IEPR Demand Forecast is necessary to ensure the forecast is as accurate as possible.

III. A FORMAL PROCESS IS NECESSARY FOR ALLOCATING RA OBLIGATIONS FOR DATA CENTER LOAD BASED ON ACTUAL INTERCONNECTION INFORMATION AND MILESTONES

As described in Section II., increased transparency and data sharing across the Commission, CCAs, IOUs, and data center customers is imperative to informing the likelihood and timing of data center loads. While this data sharing may be sufficient for longer term planning (*e.g.,* transmission planning) where the specific generation provider need not be known, when it comes to allocating LSE obligations associated with data center load for procurement purposes, a formal process is necessary for allocating data center load based upon predefined milestones.

For this reason, CalCCA filed a proposal in the CPUC's R.25-10-003 for the unique treatment of data center loads in the RA allocation process.[3] This proposal is intended to maintain the collaborative process between the CEC and CPUC, in which the CEC continues to forecast peak demand, and data centers' portion of the forecast, and make LSE specific adjustments. For the purposes of allocating RA requirements, the proposal would establish a new process for allocating new data center loads separate from the existing process used to allocate

[3] *See California Community Choice Association's Track 1 Proposals*, R.25-10-003 (Jan. 23, 2026) at 3-7: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K418/596418487.PDF; and *California Community Choice Association's Comments On Track 1 Proposals*, R.25-10-003 (Mar. 6, 2026) at 3-8: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M601/K795/601795601.PDF.

all other loads. This new process should include the following components: (1) considering data center load separately from other forecasted load for RA purposes, using actual rather than forecasted load to determine RA obligations; and (2) allocating an RA obligation to an LSE serving a data center when certain milestones, such as having chosen a LSE generation provider, having an executed interconnection agreement, and having begun construction, are met.

Establishing this new process is necessary to protect existing customers from absorbing costs associated with data center load. In particular, a process should be developed to identify the LSE that will serve the data center load and allocate RA obligations accordingly. Accounting for data center load on an individual basis for RA allocation purposes can therefore mitigate the risk of load forecast inaccuracy. By allocating data center load to the correct LSE with a high degree of certainty, as opposed to the "peanut butter" approach, this proposal has the added benefit of reducing potential cost-shifts between LSEs that experience substantial load growth associated with particular data centers (and are thus able to recover capacity costs from those data centers via rates) and other LSEs that are not.

This proposal also avoids the need to assume which LSE will serve the data center load for the purposes of RA allocations. CCAs are default providers, and they are willing and able to serve data center loads in their territories; some already serve these loads. Their intent to serve data center load does not mean that all customers will choose the CCA as their generation provider.

If there is a delay in implementing CalCCA's proposed approach, the Commission should allow for further discussion around how opt-out assumptions should be developed for large loads. For example, the Commission has provided data center load by CCA in GWh, but not by number of customers. Because opt-outs occur based upon number of customers, access to this data by number of customers would be helpful in informing how to best develop opt out assumptions.

IV. TO THE EXTENT THE COMMISSION CONSIDERS INCLUDING KNOWN LOADS AS DEFINED IN THE 2025 IEPR PROCESS IN THE DEMAND FORECAST, IT SHOULD CONTINUE TO EXCLUDE THEM FROM THE PLANNING SCENARIO

To the extent the Commission considers known loads as defined in the 2025 IEPR process in the Demand Forecast, it should continue to exclude them from the Planning Forecast, given the uncertainty of known loads and the intended purpose of the planning forecast. The known loads data is collected from each IOU, and reflects customer information regarding project capacity sector, energization data, and load profiles. Significant questions remain regarding the accuracy of the known loads information, as well as its appropriateness for inclusion in the Planning Forecast.

Known loads as defined in the 2025 IEPR process should be excluded from the Planning Forecast, given significant uncertainties related to these loads, including their actual energization dates, and the intended purpose of the Planning Forecast. Many of the known loads reported to the Commission by the IOUs include projects that require upstream capacity upgrades that could take several years to complete before a customer load can be energized. Other project timelines are dependent on customers, permitting agencies, or contractors to complete portions of the work. Other factors, such as supply chain delays and environmental reviews, could further delay energization times. It is also still unclear whether the known loads methodology has been properly adjusted to reflect the coincident peak or to resolve issues of duplication and other errors revealed during the 2025 IEPR process.

Beyond concerns about the quality of the known loads data set, issues about appropriateness of the assumptions for different use cases should be carefully considered. The primary use case of known loads data is to ensure sufficient distribution and local capacity to maintain reliability. Known loads are therefore may be appropriate to include in the Local

Reliability forecast. However, coincidence factors for this local use case are expected to differ from the coincidence factor for a use case based on system-wide demand. The Planning Forecast is applied to use cases driven by system-wide demand, as in RA requirements, bulk transmission planning, or integrated resource planning. As such, it is inappropriate to assume that the contribution of known loads to local reliability requirements would be the same as the contribution of known loads to the Planning Forecast used for system-wide requirements.

V. THE COMMISSION'S EXPLORATION OF GEOTHERMAL CHALLENGES AND OPPORTUNITIES SHOULD SEEK TO IDENTIFY AND REDUCE BARRIERS FOR GEOTHERMAL DEVELOPMENT IN AND DELIVERY TO CALIFORNIA

Geothermal resources have the potential to play a significant role in the State's clean energy transition by providing clean baseload energy. CCAs have already procured and are interested in continuing to procure geothermal resources to support diverse and clean portfolios. For example, Sonoma Clean Power, in partnership with Sonoma and Mendocino counties, is leading the GeoZone initiative to develop 600 MW of next-generation geothermal energy.[4] CCAs and other LSEs are also required to procure clean firm resources to comply with CPUC procurement orders, and the CPUC has included 3.4 GW of geothermal by 2045 in its Preferred System Plan (PSP).[5]

[4] https://sonomacleanpower.org/geozone.

[5] D.26-02-057, *Decision Requiring 2029-2032 Electric Resource Procurement and Transmitting Portfolios for 2026-2027 Transmission Planning Process*, R.25-06-019 (Mar. 5, 2026), at 60: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M601/K777/601777006.PDF.

Despite strong interest from LSEs and signals from regulators expressing a desire for a diverse resource portfolio in the State, the CAISO's interconnection queue does not reflect this diversity. Projects available for near-term procurement are predominately solar and battery storage.

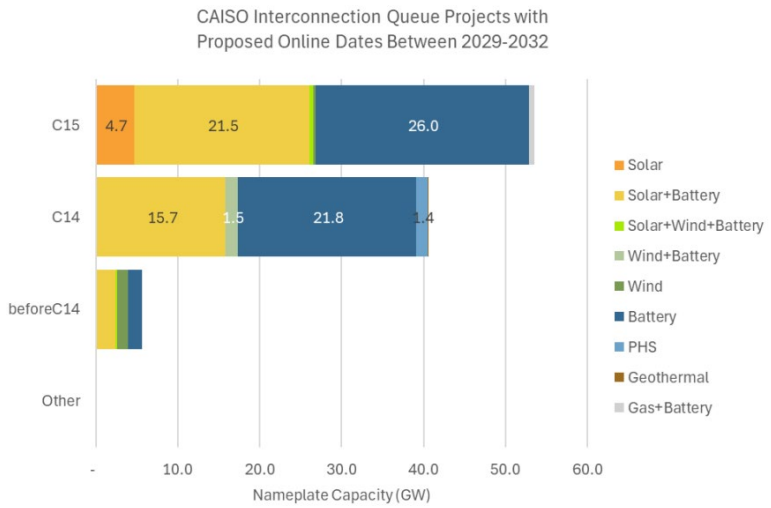

Figure 1. CAISO Interconnection Queue Projects with CODs between 2029 and 2032[6]

The current CAISO queue includes only two geothermal projects, totaling 62.5 MW.[7] Outside of the CAISO, there are 894 MW of active geothermal interconnection requests in IID and another 824 MW in the non-California West.[8] The CPUC's recently adopted PSP includes geothermal levels far exceeding the amounts in the CAISO queue, including 1.2 GW by 2031 and 3.4 GW by 2045.[9] The PSP also includes a significant amount of solar and storage, prompting questions around whether the "massive" amounts of solar and storage are feasible.[10]

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[6] CalCCA analysis of Berkeley Lab's Queued Up dataset (2025) for CAISO, available at https://emp.lbl.gov/sites/default/files/2025-08/LBNL_Ix_Queue_Data_File_thru2024_v2.xlsx

[7] CAISO Public Queue report: https://www.caiso.com/documents/publicqueuereport.xlsx; no geothermal projects are reported in the most recent Cluster 15 studies, available at https://www.caiso.com/documents/cluster-15-interconnection-requests.xlsx.

[8] Based on CalCCA analysis of Berkeley Lab's Queued Up dataset (2025) for non-CAISO interconnections in the West, available at https://emp.lbl.gov/sites/default/files/2025-08/LBNL_Ix_Queue_Data_File_thru2024_v2.xlsx

[8] Based on CalCCA analysis of Berkeley Lab's Queued Up dataset (2025) for non-CAISO interconnections in the West, available at https://emp.lbl.gov/sites/default/files/2025-08/LBNL_Ix_Queue_Data_File_thru2024_v2.xlsx

[9] D.26-02-057, at 60.

[10] D.26-02-057, at 80.

The combination of the lack of diversity in the CAISO queue and heavy reliance on solar and batteries in the CPUC's PSP suggest that investigating further the challenges and opportunities with developing geothermal is worthwhile.

The Commission should consult with relevant stakeholders to identify the magnitude and viability of geothermal opportunities in *and* out of state and investigate whether existing barriers are preventing the timely development of geothermal or other clean resources. *First*, the Commission should consult with LSEs and developers to identify areas of commercial interest within and outside of California to ensure the state is accurately planning to incorporate geothermal at viable locations. This information combined with the Commission's expertise in land use and the CPUC's efforts to map resources in the PSP will provide helpful insight into whether the State's planning processes align with commercial expectations.

Second, the Commission should also consult with developers to identify reasons why geothermal is not showing up in the CAISO queue in numbers consistent with the State's planning portfolios. Identifying root causes will help the Commission, other agencies, and stakeholders to identify solutions necessary to remove barriers. The Commission should also investigate the extent to which developers are seeking to develop geothermal outside the State. This should include the reasons for seeking development outside of California, and whether barriers, such as import capability, would prevent such out-of-state projects from offering that capacity to California LSEs.

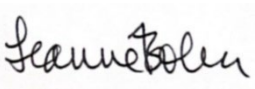
Finally, the Commission should examine siting and licensing requirements of the Commission and local entities to determine if they present any unnecessary barriers to geothermal development and the development of other clean energy resources. These efforts will

help the Commission identify potential solutions to the challenges the State is facing with bringing a diverse set of technologies to the system to support a reliable clean energy transition.

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.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

March 25, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.	Rulemaking 14-07-002
And Related Matters.	Application 16-07-015

QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF PROGRAM REPORT JANUARY 1, 2026 TO MARCH 31, 2026 FOR MARIN CLEAN ENERGY

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April 30, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.	Rulemaking 14-07-002
And Related Matters.	Application 16-07-015

QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF PROGRAM REPORT JANUARY 1, 2026 TO MARCH 31, 2026 FOR MARIN CLEAN ENERGY

Marin Clean Energy ("MCE") submits this Disadvantaged Communities Green Tariff ("DAC-GT") quarterly report in accordance with Resolution E-4999, issued June 3, 2019. Ordering Paragraph ("OP") 1(f) of Resolution E-4999 states:

> "Once an IOU has completed its first RFO or initiated customer enrollment, whichever occurs first, within 30 Calendar Days after the end of each calendar quarter, PG&E, SCE, and SDG&E shall file a report in R.14-07-002, or a successor proceeding, and serve the same report on that service list, for the previous quarter and cumulatively, with the following minimum information for the DAC-GT and CSGT programs: capacity procured, capacity online, and customers subscribed. The quarterly reports should also identify the DACs in which DAC-GT or CSGT project is located and list the number of customers participating in each program in each DAC within a utility's service territory. Finally, the quarterly reports must include the number of customers who have successfully enrolled in CARE and FERA in the process of signing up for the DAC-GT or CSGT programs."[1]

[1] Resolution E-4999, Pursuant to Decision 18-06-027, Approving with Modification, Tariffs to Implement the Disadvantaged Communities Green Tariff and Community Solar Green Tariff Programs, p. 63, OP 1(f).

As program administrators, CCAs are subject to the same reporting requirements as investor-owned utilities ("IOUs"). Accordingly, MCE hereby submits this quarterly report for DAC-GT covering the period of January 1, 2026 to March 31, 2026, attached hereto as Attachment A. Per D.24-05-065[2], the CSGT program is closed for further procurement. MCE has not procured a CSGT project to date and has closed its CSGT program.

Respectfully submitted,

/s/ *Rachel Dec*

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April 30, 2026

[2] Decision 24-06-065, Decision Modifying Green Access Program Tariffs and Adopting A Community Renewable Energy Program, issued May 30, 2024, p. 169.

ATTACHMENT A

QUARTERLY DISADVANTAGED COMMUNITIES GREEN TARIFF PROGRAM REPORT JANUARY 1, 2026 TO MARCH 31, 2026

Pursuant to Decision 18-06-027 ("Decision")[3] and in accordance with Resolution E-4999,[4] Marin Clean Energy ("MCE") files this quarterly report on the Disadvantaged Communities Green Tariff ("DAC-GT") program for the period January 1 to March 31, 2026. MCE reports on the following program metrics as required by Resolution E-4999:

1. Capacity procured and online;
2. Participating customers, including breakdown by Disadvantaged Community ("DAC");
3. California Alternate Rates for Energy ("CARE") and Family Electric Rate Assistance ("FERA") enrollment.[5]

1. Capacity Procured and Online

The DAC-GT program (branded as MCE's "Green Access" program) has a capacity cap of 4.64 MW. D.24-05-065 allocates an additional 3.609 MW to the program, for a total cap of approximately 8.25 MW.[6]

On August 27, 2021, MCE launched the first DAC-GT and CSGT solicitation, with bids due on November 19, 2021. MCE received bids for the DAC-GT program and signed PPAs to fill the total program capacity (4.64 MW). In March of 2023, the developer notified MCE that it would be unable to perform under the requirements of Conflitti PPA 2 after receiving results of the project's interconnection studies and permitting requirements, requiring modifications to the commercial operation date and price. Upon receiving the permitting and interconnection results, the developer requested a price increase for both Conflitti PPA 1 and Conflitti PPA 2. MCE negotiated with the developer to reduce the requested price increase. The developer indicated that without the negotiated price increase, it would be unable to perform under Conflitti PPA 2.

MCE performed due diligence with respect to the proposed amendments. MCE confirmed that the developer's requested price increase is below the Commission-determined price cap for DAC-GT projects. The developer's requested price increase is competitive with bids received by MCE for its 2021 DAC-GT RFO. The increased contract price requested by the developer is lower than the contract prices in all other offers MCE received in the 2021 DAC-GT solicitation. MCE determined it would be prudent and reasonable to accept the price increase and avoid the administrative cost of going back out to market as well as the higher anticipated price of offers.

[3] Decision 18-06-027, Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities, issued June 22, 2018, p. 55.
[4] Resolution E-4999, p. 40 and p. 63, OP 1(f).
[5] Resolution E-4999, OP 1(f).
[6] D.24-05-065, p. 138 and p. 170, OP 3(e).

In exchange for the negotiated price increase and COD extension, MCE negotiated that the developer must pursue the new Low Income ITC Bonus to negate the price increase. MCE also negotiated a doubling of both the Development and Performance Security of the projects.

MCE's Board of Directors reviewed the negotiated amendments to the Conflitti PPAs during its October 6, 2023 Technical Committee meeting and approved the execution of the Amendments. The amendments were executed on October 13, 2023 and submitted to the CPUC for Energy Division approval on October 24, 2023[7]. The Advice Letter was approved by the CPUC on January 31, 2024, effective November 24, 2023.

After the approval of the October 13, 2023 amendments, the counterparty learned that their financing entity had decided not to move forward after the amendments were signed. This required the developer to go back out to market for replacement financing. The developer was able to final alternate financing, but at higher financing costs which caused the projects to no longer be economically feasible at the compensation provided under the PPA. The developer requested another price increase for Conflitti 1 and Conflitti 2. After performing due diligence and determining that the increased price was reasonable and in line with market prices, MCE granted the price increase and further extensions of the construction schedule. MCE executed the additional amendments on May 3, 2024. MCE submitted the amendments to the CPUC for Energy Division approval on May 20, 2024[8]. The Advice Letter was approved by the CPUC on June 24, 2024, effective June 19, 2024. The Conflitti project (4.64 MW) came online January 27, 2026.

MCE's DAC-GT program was allocated an additional 3.609 MW of capacity in 2024. MCE launched a solicitation for new build solar to serve this additional capacity on February 23, 2026. Bids were due on April 3, 2026 are and currently being evaluated.

Enrolled customers under the DAC-GT program are currently being served by Conflitti and "interim resources" that meet the eligibility requirements of the programs in accordance with Resolution E-4999.[9] MCE is serving DAC-GT customers with solar generation from the Goose Lake project, located at 15004 Corcoran Rd., Lost Hills, CA 93249 in DAC census tract 6031001300.

2. Participating Customers

The DAC-GT program provides a 20% bill discount to eligible customers located in DACs. DACs are defined under D.18-06-027 as communities that are identified in the CalEnviroScreen ("CES") tool as among the top 25 percent of census tracts statewide, plus the census tracts in the highest

[7] Advice Letter MCE 71-E
[8] Advice Letter MCE 76-E.
[9] Resolution E-4999, p. 24 and p. 63 OP 1(i), permits PAs to serve DAC-GT customers through existing eligible resources that meet all other DAC-GT program rules on an interim basis, until new DAC-GT projects are interconnected.

five percent of CES' Pollution Burden that do not have an overall CES score because of unreliable socioeconomic or health data.[10]

The DAC-GT program is available to residential customers who live in DACs, receive generation service from MCE, and meet the income eligibility requirements for the CARE program and/or the FERA program.[11] In MCE AL 42-E-A, MCE opted to auto-enroll eligible customers that live in one of the top 10% of DAC census tracts statewide in MCE's service area if they meet certain criteria.[12]

Table 1 sets forth, for each program, the number of customers participating in each program to date. As noted above, participating customers under the DAC-GT program are being served by interim resources.

Table 1: Participating Customers in DAC-GT and Program

	DAC-GT	
Customers Subscribed as of 3/31/2026	5,585	

Table 2 indicates the number of customers participating in the DAC-GT program grouped by DAC census tract number.

Table 2: Participating Customers in DAC-GT by DAC Census Tract

Census Tract	County	City (closest by proximity)	Count
6013309000	Contra Costa	Pittsburg	47
6013310000	Contra Costa	Pittsburg	339
6013311000	Contra Costa	Pittsburg	469
6013312000	Contra Costa	Pittsburg	189
6013313101	Contra Costa	Pittsburg	270

[10] D.18-06-027, p. 16 and p. 96, Conclusion of Law 3.
[11] D.18-06-027, p. 51.
[12] MCE AL 42-E-A, p. 3.

6013313204	Contra Costa	Pittsburg	9
6013313206	Contra Costa	Pittsburg	2
6013314102	Contra Costa	Pittsburg	14
6013314103	Contra Costa	Pittsburg	4
6013314104	Contra Costa	Pittsburg	71
6013314200	Contra Costa	Pittsburg	515
6013315000	Contra Costa	Pittsburg	11
6013327000	Contra Costa	Concord	10
6013358000	Contra Costa	Rodeo	15
6013365002	Contra Costa	Richmond	362
6013366002	Contra Costa	San Pablo	10
6013373000	Contra Costa	Richmond	12
6013374000	Contra Costa	Richmond	1
6013375000	Contra Costa	Richmond	58
6013376000	Contra Costa	Richmond	442
6013377000	Contra Costa	Richmond	596
6013378000	Contra Costa	Richmond	15
6013379000	Contra Costa	Richmond	504
6013380000	Contra Costa	Richmond	17
6013381000	Contra Costa	Richmond	78
6013382000	Contra Costa	Richmond	308
6013383000	Contra Costa	Richmond	2
6013386000	Contra Costa	Richmond	9
6095250701	Solano	Vallejo	197

6095250801	Solano	Vallejo	4
6095250900	Solano	Vallejo	309
6095251000	Solano	Vallejo	16
6095251200	Solano	Vallejo	21
6095251300	Solano	Vallejo	0
6095251400	Solano	Vallejo	1
6095251500	Solano	Vallejo	29
6095251600	Solano	Vallejo	26
6095251802	Solano	Vallejo	200
6095251901	Solano	Fairfield	22
6095251902	Solano	Vallejo	24
6095252305	Solano	Fairfield	1
6095252402	Solano	Fairfield	348
6095252502	Solano	Fairfield	7
6095253500	Solano	Suisun City	1
Grand Total			**5,585**

3. CARE and FERA Customer Enrollments

MCE auto-enrolls its CARE/FERA customers into the DAC-GT program. To date, no CARE/FERA enrollment has occurred as a result of the initial DAC-GT or CS-GT enrollment for customers in MCE's service area.

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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 COMMENTS IN RESPONSE TO THE ASSIGNED COMMISSIONER'S AND ADMINISTRATIVE LAW JUDGES' RULING PROVIDING ALL-PARTY WORKSHOP INFORMATION AND SCHEDULE MODIFICATION

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April 3, 2026

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends that SCE revise the section of the Workshop Report that describes CalCCA's presentation to more accurately reflect CalCCA's and MCE's positions on:

- The definition of 'aggregator;' and
- The OpenADR communications protocol.

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

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California Community Choice Association[2] (CalCCA) submits these comments on the *Track 3 All-Party Workshop Report* (Workshop Report), filed by Southern California Edison Company (SCE) on March 20, 2026.[3] These comments are filed in response to the *Assigned Commissioner's and Administrative Law Judges' Ruling Providing All-Party Workshop Information and Schedule Modification*[4] (Feb. Ruling), dated February 6, 2026.

I. INTRODUCTION

The February 20, 2026, All-Party Workshop (Workshop) provided an important opportunity for parties to present topics related to distributed energy resource (DER)-enabled,

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

[3] *See Track 3 All-Party Workshop Report*, Rulemaking (R.) 21-06-017 (Mar. 20, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K998/602998929.PDF.

[4] *Assigned Commissioner's and Administrative Law Judges' Ruling Providing All-Party Workshop Information and Schedule Modification*, R.21-06-017 (Feb. 6, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M598/K101/598101710.PDF.

near-term, flexible connections. CalCCA, along with Marin Clean Energy (MCE), presented at the Workshop, and appreciates the opportunity to now comment on the Workshop Report. The Workshop Report captures many of the points made by CalCCA and MCE during the Workshop. As set forth below, however, CalCCA recommends the Workshop Report be revised to better reflect CalCCA's and MCE's positions on:

- The definition of 'aggregator;' and
- The OpenADR communication protocol.

A. The Workshop Report Should Be Revised to More Accurately Reflect CalCCA's Recommendation on the Definition of 'Aggregator'

The Workshop Report should be revised to more accurately incorporate CalCCA's discussion at the Workshop regarding the definition of an 'aggregator.' CalCCA's presentation included a recommendation that the term 'aggregator' not be limited to Institute of Electrical and Electronics Engineers (IEEE) 2030.5 cloud service providers, which can limit participation by grid-edge DER Management System (DERMS) providers using OpenADR or other communication protocols. CalCCA highlighted that many aggregators use other communications protocols to control on-site inverters and controllable devices and that IEEE 2030.5 is designed for inverter-based device control. Restricting the definition of 'aggregator' to an IEEE 2030.5 cloud service provider may limit the number of aggregators and non-inverter-based resources that can provide flexibility services. Further, CalCCA noted that Rule 21 does not preclude the use of other communication protocols. The Workshop Report omits CalCCA's recommendation on the definition of 'aggregator' and should therefore be revised to incorporate CalCCA's discussion of this topic at the Workshop.

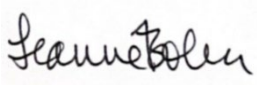
B. The Workshop Report Should Be Modified to More Accurately Reflect CalCCA's and MCE's Positions on the OpenADR Communications Protocol

The Workshop Report should also be modified to reflect CalCCA's and MCE's positions on the OpenADR Communications Protocol. MCE discussed the merits of the OpenADR communications protocol during its Workshop presentation, including its suitability for receiving and relaying demand response (DR) commands and/or price signals from utility-owned DERMS platforms. MCE noted that many investor-owned utilities in California currently use OpenADR to support their DR programs, and that OpenADR can control both inverter-based and non-inverter-based devices, whereas IEEE 2030.5 is designed to control inverter settings. Finally, MCE highlighted the cost advantages of OpenADR, which supports the scalability of load flexibility programs. The Workshop Report should therefore be modified to more accurately reflect CalCCA's and MCE's positions on OpenADR.

II. CONCLUSION

For all of 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

April 3, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	R.25-02-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING AUTHORIZING PARTIES TO FILE COMMENTS ON ISSUES TO ADDRESS IN TRACK 3

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On behalf of
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

April 10, 2026

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends that the Commission:

- Reject the Joint IOUs' recommendation to first address only their "high priority" issues of reforming or capping the RPS MPB and modifying the Energy Index MPB and instead embark on the broad exploration of PCIA reform;
- Reject the Joint IOUs' recommendation to revisit negative PCIA rates in Track 3 given the Commission has repeatedly found such rates are consistent with the statutory indifference framework;
- Adopt the Joint IOUs' request that standard confidentiality and discovery rules apply, including the use of Reviewing Representatives and adoption of the Model NDA or MPO, with the exception that the Commission require the disclosure of the data listed in CalCCA's proposed Data Matrix, thereby rejecting the Joint IOUs' baseless arguments that CalCCA has not met its burden to prove that a specialized data protocol using the Data Matrix is needed given the need for full party participation and efficient discovery;
- Reject the Joint IOUs' request for "reciprocal" data from parties unless the IOUs prove how such data is relevant to the proceeding;
- Require the Joint IOUs' and Energy Division to provide the data set forth in CalCCA's Data Matrix with a finding that such data is relevant to the proceeding; and
- Adopt CalCCA's proposed Track 3 schedule incorporating the Commission's requirement of immediate disclosure of the data in CalCCA's Data Matrix, and, if the Commission does not require immediate production of the data, at a minimum require the parties to engage in a meet and confer process to seek consensus on data issues.

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	R.25-02-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING AUTHORIZING PARTIES TO FILE COMMENTS ON ISSUES TO ADDRESS IN TRACK 3

I. INTRODUCTION

With the goal of revisiting the Power Charge Indifference Adjustment (PCIA) methodology holistically, the California Public Utilities Commission (Commission) must carefully craft both the scope of issues to be addressed, as well as the processes and mechanics of how all parties can equally and transparently contribute to the record. The objective should therefore be similar to that sought in the last PCIA proceeding:

> Customers responsible for paying the PCIA should reasonably expect that by the time this proceeding is concluded, the Commission has thoroughly reviewed why their PCIA rate is at the level it is today and how it has changed over time, which IOU resources have contributed to those costs, and when that responsibility will end. In order to assist the Commission in its review, parties need to understand the IOU portfolio and IOU procurement decisions in order to devise and analyze a going-forward cost allocation mechanism.[2]

In other words, the defined scope of issues and required access to data must allow a fulsome review of the PCIA on behalf of *all* customers, bundled and unbundled. In light of these objectives, California Community Choice Association (CalCCA) provides the following recommendations in response to party Opening Comments[3] on the Track 3 scope and data access.

First, the Commission must be careful not to tilt the scope or only scope items that will advantage one group of customers over another. The Commission should therefore reject the

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[2] *Assigned Commissioner and Assigned Administrative Law Judge Ruling Confirming Scoping Memo Issues and Modifying Schedule,* R.17-06-026 (Nov. 22, 2017), at 10.

[3] All references herein to party Opening Comments are to the Opening Comments filed in this Rulemaking, R.25-02-005, on or about March 27, 2026.

recommendations of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, the Joint IOUs) to spend the next ten months only addressing their requests to open a Track 3A to modify or cap on an interim basis the Renewables Portfolio Standard (RPS) Market Price Benchmark (MPB), and to adjust the Energy Index MPB, instead of addressing overall reforms to the PCIA methodology.[4] In addition, the Commission should reject the Joint IOUs' request to revisit whether negative PCIA rates are justified, given the Commission has repeatedly and adequately found that negative PCIA rates are appropriate under the indifference statutes.

Second, the Commission should disregard the Joint IOUs' Opening Comments mischaracterizing CalCCA's data access proposal. CalCCA has never stated that Reviewing Representatives should not be required in this case, as suggested by the Joint IOUs. Instead, CalCCA continues to advocate for a specialized data protocol only with respect to the Commission requiring the production of the data set forth in CalCCA's proposed Data Matrix[5] to allow equal access to data for formulating and analyzing proposals. CalCCA therefore does not object to using either the Commission's Model Non-Disclosure Agreement (NDA) or Model Protective Order (MPO) in this case, in lieu of the parties entering into the non-standard NDA (NSNDA) as was done in R.17-06-026, as long as CalCCA's Data Matrix proposal is incorporated. In other words, CalCCA's suggestion in Opening Comments of entering into a NSNDA similar to the 2017 PCIA case was only with respect to the agreed upon dataset, and not with respect to avoiding the use of Reviewing Representatives. In addition, CalCCA requests that both the Joint IOUs and Energy Division be required to produce the information set forth in the Data Matrix. Finally, while the Joint IOUs state that the data requirements must be "reciprocal," the Joint IOUs must prove how non-IOU data are relevant in a case aimed at finding the cost and value of the *Joint IOUs'* PCIA-eligible generation portfolios.

Third, the Commission should reject the Joint IOUs' request to carve out an expedited, interim Track 3A to address their "highest priority" issues. Instead, the Commission should first address the data access issue, and order the Joint IOUs to produce the data set forth in CalCCA's Data Matrix. Equitable access to data is foundational to this proceeding, and as such, must be the

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[4] Joint IOU Opening Comments, at 13 (proposing a Track 3A to address the RPS and Energy Index MPBs, only, from now until February 2027).

[5] CalCCA's proposed Data Matrix is attached to CalCCA's Opening Comments as Attachment A.

first item considered. In the alternative, the Commission should order the parties to meet and confer if discussions regarding the data are deemed necessary. CalCCA proposes schedules incorporating these alternatives in Section V., below.

In summary, CalCCA recommends that the Commission:

- Reject the Joint IOUs' recommendation to first address only their "high priority" issues of reforming or capping the RPS MPB and modifying the Energy Index MPB and instead embark on the broad exploration of PCIA reform;
- Reject the Joint IOUs' recommendation to revisit negative PCIA rates in Track 3 given the Commission has repeatedly found such rates are consistent with the statutory indifference framework;
- Adopt the Joint IOUs' request that standard confidentiality and discovery rules apply, including the use of Reviewing Representatives and adoption of the Model NDA or MPO, with the exception that the Commission require the disclosure of the data listed in CalCCA's proposed Data Matrix, thereby rejecting the Joint IOUs' baseless arguments that CalCCA has not met its burden to prove that a specialized data protocol using the Data Matrix is needed given the need for full party participation and efficient discovery;
- Reject the Joint IOUs' request for "reciprocal" data from parties unless the IOUs prove how such data is relevant to the proceeding;
- Require the Joint IOUs' and Energy Division to provide the data set forth in CalCCA's Data Matrix with a finding that such data is relevant to the proceeding; and
- Adopt CalCCA's proposed Track 3 schedule incorporating the Commission's requirement of immediate disclosure of the data in CalCCA's Data Matrix, and, if the Commission does not require immediate production of the data, at a minimum require the parties to engage in a meet and confer process to seek consensus on data issues.

II. THE JOINT IOUS' RECOMMENDATION TO FIRST ADDRESS ONLY THEIR "HIGH PRIORITY" ISSUES OF RPS MPB AND ENERGY INDEX MPB REFORM SHOULD BE REJECTED IN FAVOR OF THE BROAD EXPLORATION OF PCIA REFORM

CalCCA's Opening Comments support Track 3 scoping items for the broad review of the PCIA methodology as set forth in the Order Instituting Rulemaking (OIR),[6] and recommend additional scoping items to ensure a comprehensive analysis of PCIA-related issues.[7] CalCCA also appreciates the recommendations of all parties to review a breadth of issues related to the PCIA to

[6] *Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes,* R.25-02-005 (Feb. 26, 2025).

[7] *See* CalCCA Opening Comments, at 2-3.

ensure it results in indifference for both bundled and unbundled customers.[8] The Joint IOUs, however, seek to divide Track 3 into an expedited Track 3A, lasting throughout 2027, to immediately address their "highest priorities" of RPS and Energy Index MPB reform to ensure their proposals can be incorporated in 2028 rates.[9] The Commission should reject this proposal. Instead of splintering off and temporarily changing specific components of the PCIA to potentially benefit one set of customers at a point in time (*i.e.*, bundled customers when the RPS MPB may be high[10]), the Commission should instead immediately begin its holistic review of the PCIA to ensure the methodology as a whole is performing well and ensuring indifference for *all* customers.

Similar to the Joint IOUs' request to immediately modify and/or cap the RPS MPB in Track 1 (which was not added to scope and not considered),[11] the IOUs recommend that the Commission now "consider whether urgent resolution [to perceived RPS MPB issues] through an interim cap on the RPS MPB" should be issued."[12] CalCCA and all other parties agree that general

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[8] *See* The Utility Reform Network Opening Comments, at 1-4 (recommending revisiting the RPS MPB calculation and monthly MPB values); Alliance for Retail Energy Markets and Direct Access Customer Coalition (AReM/DACC) Opening Comments, at 2-9 (recommending reviewing MPB and PCIA calculations, true-ups including the ERRA Trigger process, customer and resource vintage assignment issues, and other miscellaneous issues); Joint IOU Opening Comments, at 1-5 (recommending examination of the RPS and Energy Index MPBs, re-vintaging of utility owned generation resources, comprehensive reform to PCIA MPBs, incorporation of Slice-of-Day (SOD) RA, and reform to the ERRA Trigger); California Large Energy Consumers Association (CLECA) Opening Comments, at 1-3 (recommending the consideration of PCIA policy and process reforms, including sunsetting, RPS MPB reform, SOD RA framework, revisiting consolidation of system, local, and flexible RA into a single RA MPB, and PCIA calculation transparency).

[9] *See* Joint IOU Opening Comments, at 2.

[10] Note that the assumption that the RPS MPB will remain high is likely flawed given recent softening of Renewable Energy Credit prices. While the 2026 Final RPS MPB has not yet been issued, RPS pricing has in general substantially decreased since the 2026 Forecast MPB of $62.45 was issued by Energy Division in October 2025. Therefore, the 2026 Final and 2027 Forecast MPBs will also likely decrease. *See* "California RECs Face Headwinds In January, as New Bill May Drive Prices," S&P Global (Feb. 10, 2026), https://www.spglobal.com/energy/en/news-research/latest-news/energy-transition/021026-california-recs-face-headwinds-in-january-as-new-bill-may-drive-prices#:~:text=California%20RECs%20extended%20the%20downward,allow%20plug%2Din%20solar%20systems

[11] *Assigned Commissioner's Scoping Memo and Ruling,* R.25-02-005 (Apr. 8, 2025) (omitting from scope the Joint IOU's request for RPS MPB capping and reform); *see also Joint Opening Comments of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E) and San Diego Gas & Electric Company (U 902-E) on the Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes*, R.25-02-005 (Mar. 18, 2025), at 7-15 (stating that the flaws in the RPS MPB need to be addressed along with the RA MPB through "critical" and "immediate review" and capping of the RPS MPB).

[12] Joint IOU Opening Comments, at 2.

MPB reform should be considered along with all other potential PCIA reform. As noted by CLECA, however, abrupt and frequent policy reversals based on current market conditions can have a whipsaw effect that is not necessarily indicative of the current methodology working incorrectly.[13] While the Commission deemed the abrupt RA MPB revision in Track 1 to be necessary, this PCIA proceeding should not become a venue for the IOUs to pick their "high priority" issues to benefit bundled customers depending on market conditions, while delaying more comprehensive reform. This proceeding was opened to review the PCIA methodology holistically. Therefore, the Joint IOUs' recommendation to again delay this holistic review for another year to provide them with their preferred methodology change to "take effect in 2028 rates" should be rejected in favor of the wholesale review of the methodology as promised in the OIR.[14]

III. THE JOINT IOUS' RECOMMENDATION TO REVISIT NEGATIVE PCIA RATES IN TRACK 3 SHOULD BE REJECTED GIVEN THE COMMISSION HAS REPEATEDLY FOUND SUCH RATES CONSISTENT WITH THE STATUTORY INDIFFERENCE FRAMEWORK

The Joint IOUs also request the Commission include in the Track 3 scope the issue of negative PCIA rates, and specifically request the Commission set a zero floor to prevent payment of forecasted negative PCIA rates to customers.[15] The Joint IOUs request "legal briefing in Track 3B on whether paying forecasted negative PCIA rates is permissible under existing law."[16] As already noted in CalCCA's Reply to the OIR, this issue has been the subject of considerable Commission deliberation and legal briefing, and no change in law or fact justifies its reconsideration as part of this proceeding.[17] Therefore, the Joint IOUs' request to include consideration of negative PCIA rates in the Track 3 scope should be rejected.

The Joint IOUs object to a circumstance in which "bundled service customers pay more than the cost of the portfolio serving them," stating that this "is in conflict with the statutory indifference mandate."[18] However, both statute and a significant line of Commission precedent *require* PCIA rates to be negative—on both a forecast and true-up basis—when the value of the

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13 *See* CLECA Opening Comments, at 2.
14 Joint IOU Opening Comments, at 13.
15 *Id.* at 2.
16 *Id.* at 5.
17 *See California Community Choice Association's Reply Comments on the Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes,* R.25-02-005 (Apr. 2, 2025), at 26-29.
18 Joint IOU Opening Comments, at 4.

IOUs' PCIA-eligible portfolios outweighs the cost. Sections 365.2 and 366.2 require departed customers be credited the value of any benefits that remain with bundled service customers.[19] Failing to allow for negative PCIA rates when the value of an IOU portfolio is greater than the costs of the IOU portfolio will deny departed customers the value they have imparted to bundled customers. Recognizing as much, Decision (D.) 18-10-019 applied the mandates in sections 365.2 and 366.2 and eliminated any rate floor associated with PCIA rates,[20] stating "the PCIA rate should be able to go negative and should credit departing customers when IOU portfolio value exceeds costs."[21]

The Commission has built on that foundational precedent substantially in recent years, adopting negative PCIA rates—for both bundled and unbundled customers—*nine* times across all three service territories, including in the PG&E 2023, 2024, and 2025 ERRA Forecast cases,[22] SCE's 2023, 2024, and 2025 ERRA Forecast cases,[23] and in SDG&E's 2023, 2024 and 2025 ERRA Forecast cases.[24] The issue has rarely been in dispute: it was adopted as a matter of course in eight of those nine proceedings.

The only time the issue was in dispute was in PG&E's 2023 ERRA Forecast case. There, PG&E acknowledged PCIA rates can be negative on a true-up basis but sought to implement a PCIA rate floor for the forecasted portion of the PCIA revenue requirement: the indifference amount.[25] PG&E stated it would refuse to apply a rate credit reflecting forecasted indifference amounts to those customers' bills. Instead, PG&E requested to subject those customers to a rate floor that no statute or Commission decision had authorized.[26] The floor would only be removed if a negative indifference amount actually accrued to the Portfolio Allocation Balancing Account by the end of 2023, *i.e.*, in the following year's true-up of forecasted PCIA rates.[27] In other

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19 *See* Pub. Util. Code §§ 365.2, 366.2(f)(2), (g). All subsequent code sections cited herein are references to the California Public Utilities Code unless otherwise specified.

20 D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, R.17-06-026 (Oct. 11, 2018), at 88, Finding of Fact (FOF) 20 at 155, Conclusion of Law (COL) 21 at 158 (FOF 20 stating "The PCIA rate can produce a credit to departing load if a utility portfolio provides positive net market value as demonstrated through actual recorded market transactions and realized revenues").

21 *Id*. at 88.

22 *See* D.22-12-044; D.23-12-022; and D.24-12-038.

23 *See* D.22-12-012; D.23-11-094; and D.24-12-039.

24 *See* D.22-12-042; D.23-12-021; and D.24-12-040.

25 *See California Community Choice Association's Opening Brief,* A.22-05-029 (Oct. 14, 2022), at 8-20.

26 *Id.* at 11-12.

27 *Ibid.*

words, customers were to pay PG&E's PCIA charges now but wait a year or longer for PG&E's PCIA credits.

PG&E, CalCCA, and AreM/DACC briefed the question thoroughly through 35 pages of legal and policy arguments between opening and reply briefs.[28] After five pages of discussion in D.22-12-044, the Commission agreed with CalCCA and AreM/DACC, stating: "We find no persuasive argument for [PG&E's] proposal. PG&E must continue the current practice and flow through the PCIA adjustment whether positive or negative to all bundled and departed customers."[29] Neither PG&E in that case, nor any IOU in any of the other eight cases, disputed the Commission's final decisions via an Application for Rehearing suggesting the law does not allow for negative PCIA rates.

The Joint IOUs' argument that negative PCIA rates are in tension with bundled service customer statutory protections and the Commission's indifference mandate is flawed. This one-sided argument chooses to ignore the two sides of indifference, where departed customers are entitled to the value of the benefits of the resources that remain with bundled customers. Indeed, by the IOUs' logic, positive PCIA rates are "in clear tension" with statutory protections for departed customers, which all parties would agree makes little sense.

Beyond that logical shortcoming, the IOUs' argument that negative PCIA rates conflict with the notion of indifference fails to reflect how vintaged ratesetting works. Within the Commission's PCIA framework, customers are assigned a vintage based on when they depart bundled service. Bundled customers that remain with the IOU are in the last vintage(s) and pay PCIA rates just like unbundled customers. As CalCCA's OIR Opening Comments demonstrate, both bundled and unbundled customers have enjoyed negative PCIA rates.[30] Despite the IOUs' suggestion, the issue of negative PCIA rates does not pit bundled customer against unbundled customer or create "clear tension" with either side of the indifference question.

Nothing has changed in the law or circumstances that justifies reopening this well-settled issue in Track 3. Addressing it (again) would only waste Commission and party resources.

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[28] *Id.* at 8-20; *Opening Brief of Pacific Gas and Electric Company* (U 39 E), A.22-05-029 (Oct. 14, 2022), at 32-36; *Opening Brief of the Direct Access Customer Coalition*, A.22-05-029 (Oct. 14, 2022), at 1-3; *Reply Brief of California Community Choice Association,* A.22-05-029 (Oct. 21, 2022), at 4-5; and *Reply Brief of Pacific Gas and Electric Company*, A.22-05-029 (U 39 E) (Oct. 21, 2022), at 2-10.

[29] D.22-12-044, at 3, COLS 7-9 at 14-19.

[30] *See California Community Choice Association's Opening Comments on the Order Instituting Rulemaking and Energy Division Staff Report,* R.25-02-005 (Mar. 18, 2025), at 19-21.

IV. STANDARD CONFIDENTIALITY AND DISCOVERY RULES SHOULD APPLY IN THIS PROCEEDING, WITH THE EXCEPTION THAT THE COMMISSION SHOULD REQUIRE THE PRODUCTION OF THE DATA LISTED IN CALCCA'S PROPOSED DATA MATRIX

The Commission should order that the standard confidentiality and discovery rules apply in this case, as requested by the Joint IOUs, with the only exception being that the Commission should require the production of the data listed in CalCCA's Data Matrix by the IOUs and Energy Division. CalCCA agrees, and has not objected, to Reviewing Representatives being used as required by the Commission's standard confidentiality rules. In addition, CalCCA does not object to the Model NDA or MPO being used instead of the NSNDA, p*rovided* the Commission requires the disclosure of data in CalCCA's Data Matrix.

The Joint IOUs' raise several objections to what they state "CalCCA has *suggested* in conversations with the Joint IOUs" on data access in this proceeding and regarding "*indications* from CalCCA regarding the categories of data it expects to request in connection with Track . . . ."[31] A significant portion of the Joint IOUs' comments then argue three points: (1) CalCCA has not met its burden to prove that the Commission's confidentiality rules requiring only Reviewing Representative access to confidential data should not be followed; (2) the Commission should not deviate from its standard Model NDA/MPO; and (3) CalCCA has not met its burden to prove that the Commission should deviate from its standard discovery procedures. To back up its claims, the Joint IOUs argue that the circumstances justifying departure from these standard processes in R.17-06-026 do not exist today – that the IOUs "voluntarily" provided voluminous data in that case "to support [an] *education effort*" for CalCCA and the CCAs "to gain a better understanding of [the PCIA's] mechanics . . . ."[32] While it is not necessary or useful to recount the 2017 litigation over data access and the Commission's various admonitions to and requirements placed on the IOUs, the data was most definitely *not* supplied "voluntarily" by the IOUs and CalCCA and the CCAs did not require "education" on the PCIA from the IOUs.[33] In all events, the confusion wrought by the Joint IOUs' Opening Comments as to CalCCA's position could and should have been avoided through the

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31 Joint IOU Opening Comments, at 5-6 (emphasis added).

32 *Id.* at 9 (*emphasis* added).

33 *See* CalCCA Opening Comments, at 11 (discussing the IOUs' disagreement in 2017 with stakeholders regarding the appropriate level of granularity and time periods for requested data, and the Commission noting the "serious departure" from its direction on reaching consensus and rejecting the IOU proposals to limit the scope and time period for data production).

data access meet and confer that CalCCA attempted to arrange earlier in 2026, which the IOUs rebuffed and delayed.[34]

Putting these concerns aside, CalCCA would like to clear the air on its requests for a data access protocol in this case. CalCCA never proposed *not* using Reviewing Representatives – rather, its reference to the 2017 specialized data protocol was to the agreement in advance on the data required to be produced (*i.e.*, CalCCA's proposed Data Matrix). As set forth below, CalCCA recommends the Commission order the following to move forward with an efficient discovery process and to ensure equal access to relevant data to allow parties to formulate and test proposals for comprehensive PCIA reform:

- Reviewing Representatives should be utilized, restricting access to confidential data to only non-market participants as is routinely done in the IOU ERRA cases;
- While CalCCA had recommended formulating an NSNDA similar to that agreed upon in R.17-06-026 to allow incorporation of CalCCA's proposed Data Matrix, CalCCA has no objection to instead utilizing the Model NDA (or the MPO) *provided that* CalCCA's proposed Data Matrix is incorporated; and
- Other than requiring the IOUs and Energy Division to produce the information set forth in CalCCA's Data Matrix, the parties should be required to abide by the Commission's standard confidentiality and discovery rules in this proceeding.

Adopting these measures will allow for the efficient disposition of the issues in this proceeding and avoid lengthy discovery disputes regarding the scope and nature of the data the IOUs and other parties must provide.

A. Utilizing Standard Confidentiality Rules and Discovery Procedures, Including Reviewing Representatives and the Model NDA/MPO, is Acceptable if the Commission Requires the Disclosure of the Information in CalCCA's Data Matrix

CalCCA has no objection to the IOUs' request that the standard confidentiality rules and discovery procedures, including utilizing Reviewing Representatives and adopting the Model NDA/MPO instead of the NSNDA, be used in this case if the Commission also requires the disclosure of the information in CalCCA's Data Matrix. CalCCA does not propose, and has never suggested, that CCA parties would receive data outside of the existing Reviewing Representative structure. CalCCA agrees that Reviewing Representatives are appropriate for this proceeding, and its proposed data access protocol is based on that structure.

[34] *See* CalCCA Opening Comments, at 4.

CalCCA also has no objection to utilizing the Model NDA or MPO instead of adopting an NSNDA similar to what was adopted in the 2017 case, as was proposed in CalCCA's Opening Comments. Along with the Model NDA or MPO, however, the Commission should incorporate CalCCA's proposed Data Matrix and find the listed data categories relevant to this proceeding. CalCCA's Data Matrix was formulated by CalCCA's expert (who will serve as Reviewing Representative in this case) as data necessary and relevant to explore and analyze proposals to overhaul the PCIA, which is the subject matter in the pending proceeding.[35] Each category was carefully constructed in both scope and term to fit within the requirements of Commission Rule 10.1 as to relevance and the reasonable calculation that the information will "lead to the discovery of admissible evidence," balanced against potential "burden, expense, or intrusiveness."[36]

CalCCA's Data Matrix was formulated to ensure that the data needed to effectively and equitably participate in this proceeding is efficiently obtained. Issues regarding the relevance and availability of particular categories of information held by the IOUs arose in the 2017 PCIA proceeding,[37] and continue to arise across Commission proceedings today.[38] CalCCA has continued to raise the issue of asymmetrical access to necessary data in various proceedings through the years following the 2017 PCIA proceeding, largely without successfully achieving data it and its members consider imperative to parties whose customers pay the PCIA. The Joint IOUs' beliefs on this topic appear not to have changed: it is disappointing and highly instructive that the Joint IOUs contend in Opening Comments that much of the data eventually ordered to be produced in the 2017 PCIA data access protocol was "of questionable relevance" and assert that its production was "extremely burdensome."[39]

Relevance and confidentiality disputes are likely to continue into this proceeding. Therefore, while CalCCA has no objection to the Commission ordering that "standard confidentiality rules and discovery guidelines" be followed in this proceeding, CalCCA's Data Matrix should also be adopted to prevent such disputes This, in turn, will lead to an efficient

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35 Rule 10.1 (" . . . any party may obtain discovery from any other party regarding any matter, not privileged, that is *relevant to the subject matter involved in the pending proceeding.*").

36 *Id.*

37 CalCCA Opening Comments, at 10-12.

38 *See* CalCCA Opening Comments, at 8-9, and fns. 19 and 20.

39 Joint IOU Opening Comments, at 10.

discovery process and enable all parties to proceed more quickly to the preparation and review of substantive proposals concerning PCIA reform. More significantly, this mechanism will enable all parties to access all the data necessary to participate fully and effectively in this proceeding.

B. The Joint IOUs' Baseless Arguments Refuting the Need for a Specialized Data Protocol Through the Adoption of CalCCA's Data Matrix Should be Summarily Rejected

The Joint IOUs dispute that any specialized data protocol should be adopted in this proceeding, and instead ask the Commission to issue a ruling that standard confidentiality rules and discovery procedures are adequate .[40] The Joint IOUs argue that deviation from the Commission's standard confidentiality protocol "is appropriate only in very narrow circumstances, which are not present here."[41] CalCCA has clarified above that it agrees that the standard confidentiality protection of using Reviewing Representatives should apply. However, the IOUs also claim that while the Commission departed from standard discovery practices in R.17-06-026, "the factors that justified the consensus approach in R.17-06-026 do not exist in the instant case."[42] Specifically, the Joint IOUs' argue that CalCCA has not meet its burden to prove that the "comprehensive data production that the Joint IOUs agreed to in R.17-06-026 *for education* would be reasonable in the instant case."[43] As set forth below, the Joint IOUs' are mistaken and the Commission should move forward with an Order requiring the IOUs and Energy Division to produce the information set forth in CalCCA's Data Matrix.

First, as stated in CalCCA's Opening Comments, all parties' "right of full participation" in the proceeding will be significantly constrained if the current, asymmetrical access to relevant data continues.[44] Because the Commission must base its decision on a fully developed administrative record,[45] all parties, including the Commission, must have meaningful access to the data necessary to analyze, verify, and if appropriate, challenge proposals, assumptions and methodologies offered for consideration.[46] In this case, the specialized discovery measure of adopting CalCCA's proposed addition of the Data Matrix to the Model NDA/MPO will allow

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40 *Id.* at 7.
41 *Ibid.*
42 *Ibid.*
43 Joint IOU Opening Comments, at 7.
44 *See* CalCCA Opening Comments, at 8.
45 *See* Section 1757.
46 *See* Section 1757.

efficient discovery and will ensure all parties' access to relevant and necessary data for their full participation in this proceeding.

Second, in arguing that CalCCA has not met its burden of proof required for the Commission to approve a modification to its standard discovery guidelines, the Joint IOUs misstate the impact of a prior Commission decision. Far from supporting their mistaken claim that CalCCA has not met the required burden of proof in this instance, the decision they cite actually confirms the Assigned Commissioner and Administrative Law Judge's (ALJ) decision in the 2017 PCIA proceeding to adopt an alternate data access proposal.[47] D.19-04-012 confirms the ability of parties to seek a different data access process when necessary.[48] It explicitly states the process and procedure for employing an alternative to the standard data access rules and guidelines in the 2017 PCIA proceeding was "efficient, feasible and effective."[49] While the decision denies CalCCA's Petition for Modification, it does so because other events overtook the issue: the data access issue was resolved in R.17-06-026, making the issue moot. The Commission never disavowed the process employed.

Interestingly, the Joint IOUs also now claim that "[i]t is important to note that CalCCA made *no such showing* [regarding the burden of proof] in R.17-06-026. Rather, in that case, the Joint IOUs *voluntarily agreed* to the non-standard confidentiality framework."[50] As noted above, the Joint IOUs did not "voluntarily" agree in the 2017 case to allow greater access to bundled customers' confidential market data.[51] The entire schedule for the proceeding had to be revised due to the IOUs' refusal to provide parties access to the requested data.[52] The justification for the Assigned Commissioner and ALJ adopting the modified data access proposal was the fear that parties' right of full participation would be unduly constrained without such access.[53]

For these reasons, the Commission should issue a ruling at the outset of Track 3 directing parties to follow the Commission's standard confidentiality rules and discovery procedures

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47 Joint IOU Opening Comments, at 9 (citing D.19-04-012, at 3; D.11-07-028, at 12).

48 D.19-04-012, *Decision Denying California Community Choice Association's Petition to Modify Decision 11-07-028*, R.05-06-040 (Apr. 25, 2019), at 3.

49 *Id.* at 3.

50 Joint IOU Opening Comments, at 9 (emphasis added).

51 CalCCA Opening Comments, at 4.

52 *Id.* at 10-12.

53 *Assigned Commissioner and Assigned Administrative Law Judge Ruling Confirming Scoping Memo Issues and Modifying Schedule,* R.17-06-026 (Nov. 22, 2017), at 17.

throughout the remainder of this proceeding, with the exception that the Commission also requires the disclosure of the data listed in CalCCA's Data Matrix.

C. The IOUs' Request for "Reciprocal" Access to CCA Procurement Data Must Meet Relevance Requirements

The Joint IOUs argue that the need for data in Track 3 is reciprocal, "meaning that the Joint IOUs must have equivalent ability to obtain *relevant* information, including confidential market-related data, from other parties to the proceeding, including [CCAs]."[54] The Joint IOUs have failed to prove, however, how CCA market-related data could be relevant to this proceeding. The PCIA calculates the costs and benefits of *the IOUs*' PCIA-eligible portfolios: the portfolios of other load-serving entities (LSE) are simply irrelevant to the PCIA calculation. As the Assigned Commissioner and ALJ repeatedly recognized, the data necessary for parties' participation in R.17-06-026 were held only by the IOUs, not all LSEs. Again, the situation pertaining in the instant case is identical: there still exists an asymmetry in access to the data used to establish the values and costs that feed into the PCIA calculation—the IOUs have that data, the other parties do not.

CalCCA fully supports the IOUs' position that *relevant* data is of paramount importance to this proceeding. Therefore, unless the IOUs can establish that having access to other LSEs' confidential portfolio data is somehow relevant to the calculation of the PCIA and the evaluation of possible alternatives or proposals for its modification, there is no need for reciprocity.

V. IF CALCCA'S DATA MATRIX IS NOT IMMEDIATELY ADOPTED, THE TRACK 3 SCHEDULE SHOULD PROVIDE FOR A MEET AND CONFER PROCESS TO ALLOW PARTIES TO REACH CONSENSUS ON THE DATA CATEGORIES

As noted above, CalCCA requests the Commission require that the standard confidentiality protections for the relevant data apply through the use of the model NDA or MPO. With these standard confidentiality protections, Reviewing Representatives will have access to the required data. CalCCA also requests that the Commission require immediate disclosure of the data listed in CalCCA's Data Matrix, without requiring parties to obtain such data through standard discovery processes. Approximately six months is needed from the receipt of the data for Track 3 proposal development and analysis, and as noted by the Joint IOUs to also ensure resources among the parties and the Commission are not spread thin given the overlap

[54] Joint IOU Opening Comments (citing Tr. Vol. 2, p. 164:9-11) (emphasis added).

with the IOUs'2027 ERRA Forecast proceedings.[55] Accordingly, CalCCA proposes the following schedule:

Track 3 Schedule	
Description	**Schedule**
Issuance of Track 3 Scoping Memo with Order on Data Protocols Including Adoption of CalCCA Data Matrix	June 2026
Model NDA with Data Matrix Executed by Parties/MPO Adopted by ALJ	July 2026
Data Matrix Information Disclosed	July 2026
Opening Testimony	January 2027
Rebuttal Testimony	February 2027
Evidentiary Hearing	April 2027
Opening Briefs	May 2027
Reply Briefs	June 2027
Proposed Decision	September 2027

If the Commission determines that parties must reach consensus on the scope and/or term of the items in the Data Matrix, the Track 3 schedule must provide for a meet and confer process to allow parties to seek such consensus:

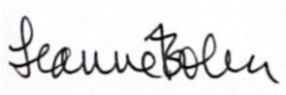
Track 3 Schedule (if Meet and Confer on data ordered)	
Description	**Schedule**
Issuance of Track 3 Scoping Memo with Order on Data Protocols and Meet and Confer Process	June 2026
Meet and confer regarding data issues	No later than July 1, 2026
Joint filing of results of meet and confer regarding data issues	No later than August 3, 2026
Model NDA with Data Matrix Executed by Parties/MPO Adopted by ALJ	TBD
Data Matrix Information Disclosed	TBD
Party Proposals	6 months after Data Matrix information is received
Opening Testimony	TBD, approx. Mar. 2027
Rebuttal Testimony	TBD, Apr. 2027
Evidentiary Hearing	TBD, May 2027
Opening Briefs	TBD, June 2027
Reply Briefs	TBD, July 2027
Proposed Decision	TBD, October 2027

[55] *See* Joint IOU Opening Comments, at 13.

VI. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests Commission adoption of the recommendations herein.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

April 10, 2026

2025 MCE Energy Efficiency Annual Report

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2025 Introduction and Summary

Introduction

MCE is a not-for-profit public agency and the preferred electricity provider for more than 600,000 customer accounts and approximately 1.8 million residents and businesses across Contra Costa, Marin, Napa, and Solano counties.[1] Since its launch in 2010, MCE has set the standard for clean energy in California, offering renewable power at stable rates, serving a peak load of 1,400 MW, and reinvesting millions into local programs that reduce greenhouse gas emissions and support community resilience.[2]

MCE's mission is to confront the climate crisis by eliminating fossil fuel greenhouse gas emissions, producing renewable energy, and creating equitable community benefits. Its vision is to lead an equitable, clean, affordable, and reliable energy economy by serving as a model for community-based renewable energy, energy efficiency, and innovative clean-tech measures and programs.

MCE offers three renewable energy products:

- Light Green: 60% renewable and 95% greenhouse gas-free, exceeding California's clean energy goals nearly two decades ahead of the state's 2045 target
- Deep Green: 100% renewable energy
- Local Sol: 100% locally produced solar energy

MCE continues to exceed state renewable energy supply standards and greenhouse gas reduction targets and has eliminated almost 540,000 metric tons of CO_2 equivalent, comparable to the carbon sequestered by approximately 583,000 acres of U.S. forests in one year.[3]

Since 2013, MCE has administered energy efficiency programs under California Public Utilities Code Section 381.1(a)-(d), initially serving gaps in Investor-Owned Utility (IOU) programs and hard-to-reach markets.[4] In 2014, the California Public Utilities Commission (CPUC) lifted these restrictions, allowing MCE to expand its portfolio of programs. Currently, Community Choice Aggregators (CCAs) that Apply-to-Administer energy efficiency programs must meet the same cost-effectiveness requirements as IOUs.[5]

In March 2026, MCE submitted a Business Plan to the CPUC, requesting authorization to extend successful programs and expand its energy efficiency portfolio to include funding for the following sectors:

1. Residential
2. Commercial
3. Industrial

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[1] MCE Clean Energy, *Areas We Serve*.
[2] MCE Clean Energy. *Our Impact*.
[3] MCE Clean Energy. *Our Impact*.
[4] California Public Utilities Code § 381.1.
[5] California Public Utilities Commission. *Decision 14-10-046*.

4. Agricultural
5. Cross-Cutting

The CPUC has approved MCE's previous Business Plans in 2018 (2019–2023) and 2023 (2024–2031), as well as its 2024–2027 Energy Efficiency Portfolio Plan under Decision 23-06-055.[6]

2025 Summary

In 2025, and throughout the more than 10 years since MCE launched its first program, MCE has managed, evaluated, and scaled EE programs in a challenging and changing service area. The portfolio focused on providing a strong suite of offerings that combined building electrification and energy efficiency solutions for each customer sector as appropriate, while ensuring that disadvantaged and hard-to-reach customers' specific needs were prioritized.

Portfolio Performance

In 2025, MCE's energy efficiency programs:

- Completed energy efficiency projects in 30 out of 38 MCE member communities.
- Achieved $2 million in total system benefits ("TSB") and issued $2.4 million in rebates.
- Prevented 9,887 metric tons of carbon dioxide emissions over the life of energy efficiency measures installed in 2025, equivalent to taking 907 gasoline-powered cars off the road for one year.
- Saved 1.07 net GWh and 93,715 net therms.

> "What inspires me most about MCE is knowing that our work makes our communities stronger, healthier, and more resilient."
>
> JAMIE TUCKEY, CHIEF CUSTOMER OFFICER

Despite positive results for MCE's programs across multiple metrics, the portfolio did not reach its forecasted cost-effectiveness ratio for the year. MCE's overall portfolio TRC ratio was 0.21, lower than the anticipated 0.84. TSB was $2 million, with a target of $23.75 million, largely because of poor outcomes from projects in the Commercial Flex Market Program, which in prior years has provided significant cost-effective savings to MCE's portfolio. As described in MCE's 2024–2031 EE application,[7] MCE's portfolio management approach includes developing a course correction plan for programs that fall below expected thresholds during the program year.[8] Because the Commercial Flex Market program performed below expectations in 2025, MCE has developed a

[6] California Public Utilities Commission. *Decision 23-06-055.*
[7] MCE filed an application for 2024-2031 under CPUC proceeding *A.22.03.012* "EE Application 24-31."
[8] Ibid, "The threshold for establishing a course correction plan will depend on the program and context for underperformance and will be determined on a case-by-case basis. The course correction plan will include (1) determining corrective actions; (2) identifying responsible parties; and (3) outlining the expected timeline for improvement.

course correction plan for it, and a description of the plan is included in the program description below.

Small Business Energy Advantage

Looking Forward — Strategies to Optimize the Portfolio and Manage Risk

For 2026 and beyond, MCE will continue working to achieve its TSB goals by implementing cost-effective EE programs through the following strategies:

- Expanded SEM Programs: MCE has invested resources in building an expanded pipeline for its Strategic Energy Management (SEM) program, which is forecasted to deliver significant savings for the remainder of the current four-year portfolio cycle.
- In 2024, MCE brought on a new Commercial Flex Market implementer selected through a competitive bidding process. Now that the new implementer has been fully onboarded, MCE expects to see significantly improved savings in that program.
- In 2024–2025, while onboarding a new implementer, MCE also responded to the addition of measure cost to the cost-effectiveness calculations for Market Access Programs. In response, MCE introduced and refined several new program guidelines to ensure project cost-effectiveness screening remains functional within this new framework without being overly complicated for market actors. MCE expects those changes to begin to produce measurable results in 2026.
- MCE introduced a resource-segment multifamily program to build on its 12 years of experience administering the equity-segment Multifamily Energy Savings (MFES) program and to allow the portfolio to offer some of the more cost-effective measures to a broader set of customers.

Through these changes, MCE expects to support the sustained growth of the EE and electrification markets in its service area, foster the closer integration of EE and demand management strategies, and ensure that all customers, especially those historically underserved by EE programs, share in the benefits of these offerings.

For each program in MCE's EE portfolio, the following sections provide a Program Description, Strategies and Achievements for 2025, and Looking Forward in 2026.

Resource Acquisition

Multifamily Strategic Energy Management Program (MCE01c)

Program Description

The Multifamily Strategic Energy Management ("MF SEM") program serves multifamily property management companies and their residents with a goal of achieving low-cost and no-cost energy savings that are sustained through behavioral and operational changes and the adoption of best practices. MF SEM uses a holistic, whole-property approach that employs a Normalized Meter Energy Consumption ("NMEC") methodology and dynamic baseline model(s) to determine eligible energy savings from all program activity at the property. MF SEM moves the energy management conversation beyond traditional capital equipment upgrades by focusing on internal processes, systems, and policies that can be improved to save energy. Savings are realized year-over-year as participating organizations develop more knowledge in a culture of continuous improvement.

The program serves properties by identifying and implementing energy-saving upgrades that would not have been possible without the program's support. Participating properties progress through a series of facilitated workshops that teach participants skills like how to map energy usage across their respective properties and develop a list of the most promising opportunities for energy savings. Savings estimates and customer incentives for operations and maintenance ("O&M"), retro-commissioning ("RCx"), and behavioral measures are calculated using pre- and post-project interval meter data. Savings estimates and customer incentives for common area, property, and in-unit projects follow applicable custom program protocols.

The program addresses market barriers by providing:

- Customized technical assistance to overcome challenges associated with the diversity of building types, ownership types, and billing configurations, and to help with analyzing potential upgrade measures.
- Property management and tenant engagement.
- Energy tracking models.
- Assessments of low-cost/no-cost, behavioral, O&M, and capital opportunities throughout the property.
- A range of participation options to best meet the current needs and abilities of properties.

Strategies and Achievements in 2025

In its third year, MF SEM continued to provide energy coaching and technical assistance to enrolled properties. The program informed participants about other MCE incentive programs to identify additional opportunities to provide greater value and service and build their

relationships with MCE. The program also introduced participants to programs offered by other program administrators, as appropriate.

Notable achievements include:

- Six multifamily properties served.
- Saved 196,000 kWh and 1,900 therms.

Looking Forward in 2026

The program will focus on serving existing program participants in their energy efficiency efforts. The program will begin to wind down in 2026, with a planned closure at the end of 2027. The program will end due to difficulty achieving energy savings by applying SEM methods in the multifamily sector through a program where cost-effectiveness measurement is required. Multifamily SEM program success requires achieving energy savings not just in common spaces, but across tenant meters as well. Although there are examples of SEM multifamily programs that achieve significant tenant and common-area energy savings (Energy Trust of Oregon, etc.), these programs offer deep and sustained tenant engagement that would not likely meet current CPUC cost-effectiveness thresholds. As the MCE program sunsets, the focus will be on connecting customers to other programs and maintaining a positive relationship with MCE.

Other strategies for 2026 include:

- A mix of individual coaching sessions, cohort-style technical workshops, and peer-to-peer learning activities.
- Setting clear customer expectations for the sunset of the program.

Commercial Flex Market Program (MCE02d)

Program Description

The MCE Commercial Flex Market program is a population-level NMEC program that uses an open market of qualified aggregators who deliver energy efficiency and demand flexibility solutions to customers within MCE's service area. The program includes a diverse mix of energy efficiency services and measures with a focus on saving and reducing energy consumption during summer peak and net peak periods in support of grid reliability.

The program includes a **diverse mix of energy efficiency services** and measures with a **focus on saving** and **reducing energy consumption** during summer peak and net peak periods in support of **grid reliability.**

The Commercial Flex Market program design allows for cost-effective energy efficiency procurement by enabling a wider network of participating aggregators without requiring direct solicitations or direct contracts with MCE. The program emphasizes the time-dependent value of savings by paying participating aggregators based on the TSB delivered by a portfolio of projects, as determined by custom savings load shapes and customer profiles. This drives aggregators to focus on high-value customers and interventions that deliver savings throughout times of the year when grid value is maximized and rewards them for doing so.

Strategies and Achievements in 2025

MCE's Commercial Flex Market retained the core principles for program implementation in 2025. In the first full year with a new implementation partner, AESC, the program focused on building the enrolled aggregator base, developing tools and services to facilitate project submissions, and launching an integrated platform for submitting and tracking project performance. In 2025, the program primarily delivered lighting and HVAC energy management system controls projects, which yielded:

- 21 project completions, with four additional projects to be completed in 2026.
- 5 participating project aggregators.
- Annual savings of 523,000 kWh.
- Annual TSB of $81,021.

Course Correction Plan

In response to 2025 underperformance in Total Resource Cost (TRC), MCE is implementing a set of targeted strategies to strengthen program outcomes. This includes improving cost-effectiveness, reducing program risks, and growing the program portfolio. In 2026 MCE will implement the following corrective actions:

1. **Administrative cost reduction through the phasing out of initial program start-up costs.** The Program Implementer has completed the onboarding and program ramp-up activities in 2025 which in turn eliminates this cost in 2026 and beyond, which will improve TRC in the future.
2. **Implementation of a tiered incentive structure that prioritizes and rewards projects with higher project TRC.** By aligning incentive levels with projected TRC, this approach will encourage aggregators to develop projects with deeper savings and at a lower cost.
3. **Focusing on program solutions that increase both the number of projects and average TSB per project**. This will be achieved through improved aggregator engagement and refined project screening. This includes more aggregator management support from the implementation partner and the expansion of customer targeting.
4. **Performing a risk assessment of forecasted claims to determine if there is a need to modify the current approach of claiming the entire estimated project savings**. In

2025, MCE submitted several negative project claims because metered savings from projects that completed measurement and verification (M&V) were significantly less than the initial forecasts. This resulted in $81,021 TSB applied to MCE's 2025 Resource Portfolio.

Looking Forward in 2026

MCE will continue to use innovative strategies to drive customer participation, expand the program benefits, and increase cost-effectiveness. MCE will also continue to coordinate with population-level NMEC programs offered by other CCAs and PAs throughout MCE's service area and the state to improve MCE's program design and drive beneficial grid impacts.

Building on the foundation laid in 2025, the program will focus on increasing the number of projects as well as per-project TSB. With a robust pool of enrolled aggregators, MCE and its implementer will seek to increase the number of those actively submitting projects by deepening engagement including providing technical support and feedback on initial projects and facilitating partnerships between larger aggregators and smaller installing contractors where feasible.

Other program changes and improvements include:

- Support aggregator and contractor partnerships to increase engagement and program participation
- Launch of a tiered incentive structure to encourage high-performing, cost-effective projects
- Integrate and leverage the recently approved CPUC Integrated Demand Side Management funding

Together with the course correction plan, these strategies will position the program to enhance TRC performance, mitigate underperformance risk, and deliver more cost-effective energy savings over the coming year.

Energy Management Program (MCE02a-c, MCE10a-c, MCE11a-c)

Program Description

The MCE Energy Management Program is a comprehensive program designed for agricultural, industrial, and commercial customers within MCE's service area.[9] The Energy Management Program is designed to provide individualized services to identify energy efficiency opportunities, develop and evaluate implementation options, and provide incentives in the form of technical assistance, money-back rebates, and financing.

MCE employs multiple participation pathways, leaning heavily on SEM as a primary strategy for engaging agricultural and industrial customers, while also offering the opportunity to pursue deemed rebates and custom projects to realize energy efficiency and cost-effectiveness goals. SEM plays a key role in the Energy Management Program to help address market barriers and achieve program objectives through long-term engagement with customers. SEM offers customers cohort-style training workshops and individual site activities.

[9] The program was previously called the AIR program but was rebranded in 2025.

The Energy Management Program includes the following objectives:

- Improve education and knowledge about energy use and associated economic and environmental impacts in the agricultural and industrial sectors within MCE's service area.
- Provide customers with a single point of contact ("SPOC") for their energy journey, simplifying otherwise complex and potentially competing project interests, while also connecting them to other available local and regional offerings.
- Create multiple pathways to participate under a single program umbrella, to maximize participation and optimize value to customers based on their needs.
- Ensure program impacts are verifiable and defensible and that incentive payments align with realized savings where feasible.

NOTABLE ACHIEVEMENTS INCLUDE:

Net energy savings of 800,800 kWh and 32,600 therms

Strategies and Achievements in 2025

In 2025, the MCE Energy Management program focused on recruitment for SEM customers with especially high energy usage, with coordination between the implementer and MCE's Business Development staff. As a result of these efforts, the program enrolled customers with high energy-saving potential in 2026 and beyond. The program also contracted with a new technical review firm to align with best practices of SEM project review. Finally, the program established new KPIs to increase transparency and track implementer engagement with customers and trade professionals. The program implementer hired new sales staff to support this work.

Looking Forward in 2026

The Energy Management Program will work to deepen relationships with recently enrolled SEM participants to maintain momentum with energy-saving improvements. These efforts will include both individual coaching for participants and cohort activities to encourage the sharing of best practices in support of behavioral goals. The program will also have a renewed focus on recruiting customers interested in capital improvement projects (via the deemed or custom pathways) that have a higher cost-effectiveness ratio and TSB. The program is investigating electrification measures and associated incentive structures to improve enrollment in these pathways.

Other program changes and improvements include:

- Development of an SEM "graduate" program to support program participants that have completed six years with the program and would benefit from consistent and ongoing coaching and access to incentives.
- Assessment of TSB as a payment determinant rather than kWh and therm savings.

Residential Flex Market Program (MCE01d)

Program Description

The MCE Residential Flex Market program offers a flexible path for aggregators and contractors to bridge customer needs, MCE's energy efficiency resource needs, and grid reliability. The program's hybrid deemed and performance-based (NMEC) incentives push aggregators to deliver projects with maximum savings, particularly during summer peak and net peak periods.

The program focuses on customer benefit by requiring aggregators to pass through the deemed incentive, which represents 80% of the total incentive, directly to the customer. The remaining 20% of the total incentive is designated as a performance-based bonus for the aggregator and is intended to incentivize high-quality projects that can provide measurable deep energy savings.

Strategies and Achievements in 2025

After restructuring, MCE's Residential Flex Market relaunched in June 2025. Because projects are primarily aggregator-led, the program focused heavily on contractor and aggregator recruitment, enrollment, and onboarding. As a result of those efforts, the program has 27 participating contractors.

By layering multiple incentive programs, including TECH Clean California and other locally available rebates, such as the City of Pinole's Energy Enhancement Rebate, contractors were able to offer customers an affordable, clean energy option for water heating.

The program simultaneously benefitted from the allocation of MCE funds to supplement incentives for the installation of heat pump water heater projects. The additional funding drove program participation, and by layering multiple incentive programs, including TECH Clean California and other locally available rebates such as the City of Pinole's Energy Enhancement Rebate, contractors were able to offer customers an affordable, clean energy option for water heating. The program delivered exclusively heat pump water heating projects in 2025, which yielded the following metrics:

- 21 projects throughout MCE's four county service area.
- 6 participating aggregators submitted projects.
- Annual savings of (229,260) kWh*.
- Annual savings of 2,992 therms.

*Electrification projects generate negative kWh savings, but significant therm savings.

Looking Forward in 2026

The program will build on the momentum gained in the latter half of 2025 by continuing to build a robust contractor network and provide valuable incentives that enable customers to make electrification upgrades. Additionally, MCE plans to expand the scope of the supplemental incentives provided to customers to include heat pump HVAC, which will enable the program to engage a wider contractor base to serve broader customer needs.

Equity

Multifamily Energy Savings Program (MCE01)

Program Description

The Multifamily Energy Savings Program (MFES) delivers energy efficiency and electrification improvements to affordable multifamily properties within MCE's service area. MFES provides no-cost technical assistance and rebates to property owners and tenants to support the adoption of comprehensive high-efficiency electrification and energy efficiency measures. The program supports efforts to decarbonize and increase energy efficiency in existing affordable multifamily buildings, particularly those that have been traditionally underserved by energy efficiency programs.

The program addresses key market barriers by:

- Providing customized technical assistance to navigate challenges related to diverse building types, ownership structures, and billing configurations
- Educating property owners on participation options tailored to their property's needs and guiding them through potential upgrade opportunities
- Bridging funding gaps to support equitable whole-building improvements, even when certain units or measures do not qualify for other incentive programs

Through flexible incentives and comprehensive support, MFES empowers property owners to implement meaningful improvements that enhance comfort, reduce utility costs, and promote long-term sustainability.

Strategies and Achievements in 2025

In 2025, MCE continued building on the expanded MFES measure list introduced in 2023, which includes building electrification upgrades such as heat pump HVAC, heat pump water heaters, induction stoves, and heat pump dryers. The program also maintained its streamlined incentive-layering process, integrating external programs such as the Low-Income Weatherization Program (LIWP) and TECH Clean California, while also combining MFES rebates with remaining Low-Income Family and Tenants (LIFT) rebates[10] and rebates sourced from MCE operating funds, including the Community Housing Grant and Local Program Fund. The MCE Community Housing Grant and Local Program Fund rebates enable electrification projects and more comprehensive energy upgrades, for example, by covering costs for electrical infrastructure, health and safety upgrades, and induction-compatible cookware.

In total, MFES supported energy efficiency and electrification upgrades in 424 housing units across 12 properties in Contra Costa and Marin counties. Of these 12 properties, seven initiated their projects with MFES (or LIFT) prior to 2025, and another five began and completed their retrofit projects within the program year. The number of properties with completed projects

[10] The LIFT program (Energy Savings Assistance Program) closed to new program participants in 2023, but MCE continued to disburse payments to properties with multi-year projects with LIFT rebate reservations through 2025.

increased 50 percent from 2024, and rebate payments increased nearly 14-fold between 2024 and 2025 due to the larger number of multi-year projects that completed construction in 2025.

In 2025, the MFES team explored new industry partnerships to make emerging technologies accessible to MFES program participants. For example, MCE provided MFES rebates to enable Emerson Arms, a 32-unit affordable housing property in Martinez, to install Copper's 120-volt "Charlie" induction ranges in 32 residential units as part of comprehensive property-wide energy efficiency and electrification upgrades. As part of this project, the California Market Transformation Administrator (CalMTA) completed a field study that captured the cooking behavior of tenants who received the ranges and the performance, power requirements, and energy consumption of the installed equipment to inform future multifamily installations. The study findings are available here: https://calmta.org/wp-content/uploads/2025/09/120V-Battery-Equipped-Induction-Ranges-Field-Study.pdf.

In 2025, the MFES team again demonstrated a flexible and collaborative approach to making energy efficiency and electrification upgrades more accessible to affordable multifamily properties in MCE's service area. This benefits property owners, residents, the environment, and the cleantech marketplace.

Looking Forward in 2026

Multifamily energy efficiency and electrification projects often span multiple years and require sustained hands-on support due to their complexity. This complexity includes:

- Large project scopes and budgets.
- Earning approval for these larger projects from multiple decision-makers.
- Designing construction schedules to minimize disruptions for tenants.
- Navigating programmatic nuances such as different program eligibility guidelines and avoiding double-dipping program budgets.
- Supporting property managers and contractors as they gain familiarity and comfort with newer technologies and adapting construction plans to site conditions, as needed.

To accommodate these longer project timelines, in 2025, the MFES team realigned program goals to show developmental progress and introduced performance payments for completing project milestones rather than waiting to pay the full rebate upon project completion. These enhancements are in addition to the earlier introduction of more flexible MCE-revenue-funded electrification rebates (Community Housing Grant, Local Program Funds) to fill budget gaps.

MFES Resource Launch in 2026

Despite MFES' successes, building electrification — a key component of California's decarbonization strategy — remains out of reach for many multifamily properties in MCE's service area. To help close this gap, MCE is launching the MFES Resource Program in 2026 to expand access to electrification incentives, financial support, and technical assistance beyond deed-restricted properties. MCE is also increasing incentive levels for cost-effective electrification measures. The MFES team will continue to leverage partnerships with BayREN and others to connect shared customers with the program offerings that best maximize benefits for tenants and property owners. MCE will also continue to support commercialization of new high-efficiency technologies and making the technologies accessible to affordable multifamily communities.

Home Energy Savings Program

Single Family Home Energy Savings ("HES") Program (MCE08)

Program Description

MCE's single-family direct-install program is branded to customers as the Home Energy Savings (HES) Program. HES provides no-cost energy-saving gifts, home assessments, and home upgrades to eligible single-family homeowners and renters in MCE's service area. The program focuses on improving home efficiency, making homes building-electrification-ready, and installing electrification technologies. This program targets customers in Disadvantaged Communities ("DACs") whose household income exceeds the limit for services through programs such as the ESA program, but who are still income-constrained (moderate income) and unable to participate in shared-cost market-rate programs.

The program goals are to:

- Provide comprehensive home upgrades to improve the efficiency of low- to moderate-income single-family homes.
- Increase knowledge about energy use and associated economic and environmental impacts in the residential sector within MCE's service area.

- Provide customer service via a SPOC for the customers' energy journey, while also connecting them to other available local and regional offerings.
- Ensure program measures and the delivery model meet customer needs, produce health, safety, and comfort benefits, and achieve forecasted savings targets.

Strategies and Achievements in 2025

In 2025, HES upgraded 351 low- to moderate-income homes, with duct sealing and attic insulation among the most common upgrades. The program installed 142 electrification measures in 96 homes, providing more electrification installations than in any previous year.

To expand the measure offerings for this program, MCE partnered with Franklin Energy and PG&E to develop a Residential Deeply Buried Ducts workpaper in late 2023. This statewide workpaper incentivizes comprehensive envelope measures and enables program administrators to capture greater savings when combining duct sealing and repair, sealing of the attic plane, and increasing attic insulation in their scopes of work. In 2025, MCE was able to install the Deeply Buried Ducts measure in over 75 homes.

Many low- and moderate-income households require circuit upgrades to install electrification equipment. Because CPUC program funding only covers equipment costs, MCE supplemented the HES program with its own funding to cover home repairs needed for 52 additional electrification installations in 2025.

To further expand the reach of the Home Energy Savings program, in 2023, MCE partnered with GRID Alternatives and the City of Richmond on a Transformational Climate Communities (TCC) grant. MCE layers the TCC funds and HES funds to serve residents of Santa Fe, Coronado, and Iron Triangle neighborhoods with a greater scope of services. TCC funds enable necessary electrical repairs, panel upgrades and additional electrification installations for Home Energy Savings customers.

MCE prioritized customer service and program feedback this past year. While HES has always utilized post-installation satisfaction surveys, in 2025, staff pivoted to a phone survey. Calling customers directly within 72 hours after they received service resulted in a 30% increase in the overall response rate and the program finished the year with a 97.2% satisfaction rate. HES also launched a maintenance campaign for customers who received a heat pump hot water heater. Customers are now provided with best-practice guidelines for use and maintenance reminders for their new equipment on a quarterly basis. This extends program support beyond initial installations and allows MCE to proactively open lines of communication for customers to ask questions or show interest in additional energy efficiency offerings.

Looking Forward in 2026

In 2026, MCE plans to maintain the Home Energy Savings Program as a comprehensive home upgrade offering. The program will continue to target moderate-income single-family customers, while serving all low- to moderate-income residents who qualify. The program will continue to focus on improving home energy efficiency, with an emphasis on electrification-readiness and ways to increase its electrification offerings.

Other program changes and improvements for 2026 include:

- Improving the SPOC model through continued coordination with BayREN and PG&E and developing coordinated enrollment referrals with programs serving customers above and below the moderate-income eligibility guidelines and outside of MCE's service area.
- Expanding program outreach and enrollment strategies to build greater trust with income-qualified customers.
- Continuing to layer in non-CPUC funding to provide complementary services to HES participants that enable energy efficiency and electrification upgrades and reduce program deferrals.
- Expanding 2025's customer maintenance campaign to include specifics on all HES electrification offerings (heat pump HVAC, mini-splits, induction cooking) and offer it to all current and past HES customers.

Small Business Energy Advantage (SBEA) (MCE02e)

Program Description

The Small Business Energy Advantage (SBEA) program delivers meaningful bill savings and EE education to equity commercial customers[11] throughout MCE's service area. SBEA participants receive site assessments, select energy-saving upgrades, and are assigned installers to complete no-cost and reduced-cost projects. SBEA partners with local community-based organizations (CBOs) and Green Business Programs (GBPs) to further outreach efforts and ensure equitable access to program resources.

Program goals are to:

- Serve small businesses located in underserved communities throughout the MCE service area.
- Improve access to program services through local engagement by building an Outreach Network Team (ONT) made up of CBOs and GBPs.
- Deliver meaningful energy savings and bill savings.
- Focus on delivering Non-Energy Benefits (NEBs) such as improved health, comfort, and safety.
- Fill gaps in services that are not currently provided by other MCE programs.

[11] MCE defines "Equity customers" as residential customers and businesses within identified "Environmental and Social Justice Communities" ("ESJ Communities") by the California Public Utilities Commission's Environmental and Social Justice Action Plan, with the additional modifier of households at or below 400% of the Federal Poverty Level ("FPL") or 80% of Area Median Income.

Of the projects completed, **137** were for participants located in Low-income census tracts, **54** were in Disadvantaged Communities (DACs), and **133** were businesses that qualified as Hard-to-Reach (HTR)[12].

Strategies and Achievements in 2025

In 2025, SBEA completed 167 EE projects at 165 small businesses, resulting in estimated bill savings of $82,500 per year across all participants. An additional 29 enrolled participants received energy education but did not complete installations. Of the projects completed, 137 were for participants located in low-income census tracts, 54 were in Disadvantaged Communities (DACs), and 133 were businesses that qualified as Hard-to-Reach (HTR).[12]

To improve access to program resources, SBEA representatives conducted door-to-door campaigns in the cities of Vallejo, San Rafael, and Napa. Combined, the three city campaigns engaged over 500 individual businesses, with 99 of them enrolling to receive program services. SBEA achieved these results through strong relationships with local organizations. In 2025, the program contracted with five CBOs and three GBPs to help drive outreach and engagement success. In tandem with the city campaigns, SBEA collaborated with the MCE Cares Credit to enroll 730 small businesses to receive a $25 monthly bill credit.

Looking Forward in 2026

The program aims to build on the momentum gained in 2025 by further investing in a community-driven approach to outreach and engagement. SBEA will be conducting two door-to-door community campaigns in 2026. To support these campaigns and boost engagement activities, the program aims to bring on one to two additional CBOs based in the communities the campaigns will serve.

In tandem with an increased community engagement focus, SBEA also plans to improve program offerings in 2026. The program will adjust measure incentives to encourage more comprehensive projects that include a greater variety of measure types.

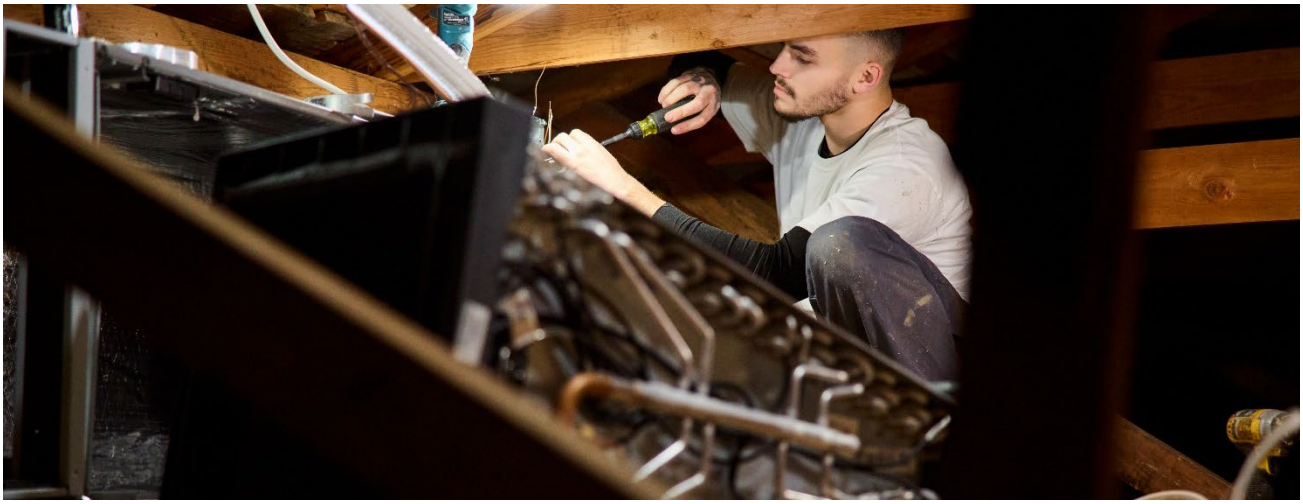
The program goals for 2026 are:

- Conduct two door-to-door community campaign events.
- Onboard one to two CBOs to the ONT.
- Enroll 140 small businesses to receive energy-saving upgrades.
- Educate 204 customers with tips and tricks to further save energy.

[12] A single participating business may meet multiple equity indicators which explains why the results per equity sector do not add up to match the total number of program participants.

Market Support

Green Workforce Pathways Program (MCE16)



Green Workforce Pathways Program

Program Description

MCE's Green Workforce Pathways (GWP) program supports the development of the residential energy efficiency and electrification workforce by enhancing the skills of the existing contractor workforce and creating pathways for job seekers into sustainable, long-term careers in building electrification.

The GWP program provides technical support in electrification and home performance to residential contractors, as well as access to industry-focused educational opportunities for new and existing staff. GWP also provides individualized wraparound support services for job seekers, including interview and resume skills, as well as sourcing and matching job seekers with local residential energy efficiency and electrification contractors.

The program is designed to leverage industry and stakeholder expertise to provide long-term, relevant training opportunities for the existing energy efficiency and electrification contractor workforce, as well as sustainable, long-term career on-ramping opportunities for job seekers.

Strategies and Achievements in 2025

In 2025, the GWP program supported 14 electrification contractors and 64 job seekers. Contractors were provided with new hire onboarding support, cash stipends for completing heat pump manufacturer-led training, and on-demand building performance training.

The GWP program supported job seekers with soft skills training through its Career Readiness Workshop. Contractors emphasized that soft skills such as customer service and sales training are essential for success in residential service roles. Out of 64 job seekers, 13 were matched with electrification contractors and completed paid work experience.

In an ongoing effort to support equitable access to training, GWP began offering Career Readiness Workshops in Spanish. In 2025, more than half of the job seekers who attended Career Readiness Workshops (33 of 64) were primarily Spanish-speaking.

In partnership with the Emerald Cities Collaborative and the PG&E Energy Center, MCE hosted a multi-week training course to help increase the number of small, diverse contractors working in the clean energy industry. The academy is a no-cost training opportunity for minority/BIPOC-owned, women-owned, veteran-owned, and/or disadvantaged business enterprises (MWDBE).

MCE also partnered with local water heater distributors to provide on-site contractor training to nine small plumbing businesses. Participating businesses received heat pump water heater training and were connected to information about local energy efficiency programs.

GWP implementers continued engaging community workforce partners and performing outreach to electrification contractors in efforts to grow the demand for electrification careers. The implementers continued refining more efficient onboarding processes for both contractors and jobseekers to enhance the participant experience.

Looking Forward in 2026

For 2026, program work will include:

- Leveraging relationships with residential decarbonization programs, industry trade groups, and trade ally memberships to promote regional workforce development in residential energy efficiency and decarbonization.
- Strengthening the pipeline for jobseeker-to-contractor matchmaking throughout all MCE service area counties.
- Targeting outreach to electrification contractors in MCE's service area.
- Providing stipends to contractors and their staff to participate in approved industry-led electrification training.
- Continuing to offer Career Readiness Workshops and soft skills training to job seekers in partnership with workforce development agencies and their trainees, as well as program participants.

Community Engagement Efforts

In 2025, MCE funded community engagement efforts that, among other things, supported discussion and customer feedback, as well as access to energy efficiency and electrification options.[13]

In 2025, MCE's Community Power Coalition hosted its second annual Symposium, convening approximately 100 attendees; the event featured speakers from clean-tech companies, community foundations, and elected offices to explore energy efficiency, distributed energy, electrification, and program and customer engagement improvements, among many other community-focused topics. The MCE Community Partnership Program funded projects that provided community outreach and energy education for limited-English-speaking residents, contractor engagement on efficiency programs and rebates, and targeted small business outreach in a disadvantaged community.

MCE's community engagement efforts help build strong coalitions with local governments that allow MCE to align customer programs and offerings with regional energy priorities. In 2025, MCE staff delivered 52 presentations to city councils, climate action committees, and other civic forums.

To support workforce and community development, MCE funded grants to a local workforce organization supporting transitional-age youth entering clean energy careers; a nonprofit providing wraparound services, including energy affordability programs for immigrant communities, and a local municipality implementing energy efficiency and electrification initiatives to enhance community resilience.

[13] All community engagement efforts listed are funded by MCE revenues and bolster MCE's CPUC-funded portfolio of programs.

2025 Portfolio Data

Budget and Expenditures

Program-level

Program ID	Program Name	Budget Category	Authorized Budget Amount	Percent of Total Portfolio Budget	Expenditure Amount	Percent of Total Portfolio Expenditures
MCE01	MFES	Administrative	$28,461	0.2%	$28,747	0.3%
		Direct Implementation (Non-Incentive)	$657,710	3.5%	$299,639	3.0%
		Direct Implementation Incentive	$45,395	0.2%	$659,726	6.7%
		Marketing, Education and Outreach	$40,000	0.2%	$0	0.0%
		Program Total	$771,565	4.1%	$988,112	10.0%
MCE01c	MF SEM	Administrative	$55,655	0.3%	$23,956	0.2%
		Direct Implementation (Non-Incentive)	$294,477	1.6%	$75,979	0.8%
		Direct Implementation Incentive	$58,946	0.3%	$14,000	0.1%
		Marketing, Education and Outreach	$15,000	0.1%	$23	0.0%
		Program Total	$424,078	2.3%	$113,958	1.2%
MCE01d	Res EE Market	Administrative	$9,716	0.1%	$35,099	0.4%
		Direct Implementation (Non-Incentive)	$263,411	1.4%	$156,993	1.6%
		Direct Implementation Incentive	$1,121,874	6.0%	$0	0.0%
		Marketing, Education and Outreach	$20,000	0.1%	$0	0.0%
		Program Total	$1,415,001	7.6%	$192,092	1.9%
MCE02a	Com Deemed	Administrative	$9,716	0.1%	$33,561	0.3%
		Direct Implementation (Non-Incentive)	$201,667	1.1%	$105,740	1.1%
		Direct Implementation Incentive	$207,275	1.1%	$17,690	0.2%
		Marketing, Education and Outreach	$0	0.0%	$0	0.0%
		Program Total	$418,658	2.2%	$156,992	1.6%
MCE02b	Com Custom	Administrative	$9,716	0.1%	$33,561	0.3%
		Direct Implementation (Non-Incentive)	$518,801	2.8%	$105,740	1.1%
		Direct Implementation Incentive	$561,092	3.0%	$10,039	0.1%
		Marketing, Education and Outreach	$0	0.0%	$0	0.0%
		Program Total	$1,089,609	5.8%	$149,341	1.5%

MCE02c	Com SEM	Administrative	$34,716	0.2%	$23,956	0.2%
		Direct Implementation (Non-Incentive)	$524,272	2.8%	$90,282	0.9%
		Direct Implementation Incentive	$101,302	0.5%	$14,087	0.1%
		Marketing, Education and Outreach	$15,000	0.1%	$23	0.0%
		Program Total	$675,290	3.6%	$128,348	1.3%
MCE02d	Com Flex Market	Administrative	$1,219,887	6.5%	$30,308	0.3%
		Direct Implementation (Non-Incentive)	$1,271,082	6.8%	$1,750,377	17.8%
		Direct Implementation Incentive	$3,607,733	19.3%	$1,691	0.0%
		Marketing, Education and Outreach	$20,000	0.1%	$0	0.0%
		Program Total	$6,118,701	32.7%	$1,782,376	18.1%
MCE02e	Com SBEA	Administrative	$9,716	0.1%	$28,747	0.3%
		Direct Implementation (Non-Incentive)	$904,207	4.8%	$1,230,313	12.5%
		Direct Implementation Incentive	$0	0.0%	$0	0.0%
		Marketing, Education and Outreach	$0	0.0%	$1,017	0.0%
		Program Total	$913,923	4.9%	$1,260,077	12.8%
MCE08	SF HES	Administrative	$39,664	0.2%	$38,329	0.4%
		Direct Implementation (Non-Incentive)	$849,380	4.5%	$772,132	7.8%
		Direct Implementation Incentive	$2,085,202	11.1%	$1,694,534	17.2%
		Marketing, Education and Outreach	$0	0.0%	$118,618	1.2%
		Program Total	$2,974,246	15.9%	$2,623,613	26.6%
MCE10a	Ind Deemed	Administrative	$9,688	0.1%	$23,979	0.2%
		Direct Implementation (Non-Incentive)	$66,657	0.4%	$75,529	0.8%
		Direct Implementation Incentive	$15,319	0.1%	$0	0.0%
		Marketing, Education and Outreach	$0	0.0%	$0	0.0%
		Program Total	$91,663	0.5%	$99,508	1.0%
MCE10b	Ind Custom	Administrative	$9,688	0.1%	$23,979	0.2%
		Direct Implementation (Non-Incentive)	$156,464	0.8%	$75,529	0.8%
		Direct Implementation Incentive	$178,362	1.0%	$0	0.0%
		Marketing, Education and Outreach	$0	0.0%	$0	0.0%
		Program Total	$344,514	1.8%	$99,508	1.0%

MCE10c	Ind SEM	Administrative	$34,688	0.2%	$23,956	0.2%
		Direct Implementation (Non-Incentive)	$243,354	1.3%	$75,529	0.8%
		Direct Implementation Incentive	$49,821	0.3%	$12,163	0.1%
		Marketing, Education and Outreach	$15,000	0.1%	$23	0.0%
		Program Total	$342,863	1.8%	$111,671	1.1%
MCE11a	Ag Deemed	Administrative	$6,708	0.0%	$23,979	0.2%
		Direct Implementation (Non-Incentive)	$53,374	0.3%	$75,529	0.8%
		Direct Implementation Incentive	$16,865	0.1%	$0	0.0%
		Marketing, Education and Outreach	$0	0.0%	$0	0.0%
		Program Total	$76,946	0.4%	$99,508	1.0%
MCE11b	Ag Custom	Administrative	$6,708	0.0%	$23,979	0.2%
		Direct Implementation (Non-Incentive)	$47,660	0.3%	$75,529	0.8%
		Direct Implementation Incentive	$23,830	0.1%	$0	0.0%
		Marketing, Education and Outreach	$0	0.0%	$0	0.0%
		Program Total	$78,198	0.4%	$99,508	1.0%
MCE11c	Ag SEM	Administrative	$31,708	0.2%	$23,956	0.2%
		Direct Implementation (Non-Incentive)	$202,592	1.1%	$75,529	0.8%
		Direct Implementation Incentive	$36,270	0.2%	$0	0.0%
		Marketing, Education and Outreach	$15,000	0.1%	$23	0.0%
		Program Total	$285,570	1.5%	$99,508	1.0%
MCE16	Green Workforce Pathways	Administrative	$27,911	0.1%	$28,747	0.3%
		Direct Implementation (Non-Incentive)	$931,034	5.0%	$834,655	8.5%
		Direct Implementation Incentive	$0	0.0%	$0	0.0%
		Marketing, Education and Outreach	$0	0.0%	$0	0.0%
		Program Total	$958,945	5.1%	$863,402	8.8%
MCE98	EM&V	EM&V	$307,090	1.6%	$154,433	1.6%
		Administrative	$0	0.0%	$74,234	0.8%
		Program Total	$307,090	1.6%	$228,666	2.3%
MCE101-Equity-PS	Equity Portfolio Support	Administrative	$115,484	0.6%	$98,269	1.0%
		Direct Implementation (Non-Incentive)	$0	0.0%	$317,951	3.2%
		Program Total	$115,484	0.6%	$416,220	4.2%
MCE101-MS-PS	Market Support Portfolio Support	Administrative	$23,766	0.1%	$19,101	0.2%
		Direct Implementation (Non-Incentive)	$0	0.0%	$54,663	0.6%
		Program Total	$23,766	0.1%	$73,764	0.7%

MCE101-RA-PS	Resource Portfolio Support	Administrative	$306,350	1.6%	$127,819	1.3%
		Direct Implementation (Non-Incentive)	$0	0.0%	$139,790	1.4%
		Program Total	$306,350	1.6%	$267,608	2.7%
MCE100	Resource Portfolio Support	Direct Implementation (Non-Incentive)	$1,000,000	5.3%	$0	0.0%
		Program Total	$1,000,000	5.3%	$0	0.0%
Portfolio Total			**$18,732,461**	**100.0%**	**$9,853,780**	**100.0%**

Sector-level

Sector	Budget Category	Authorized Budget Amount	Percent of Total Portfolio Budget	Expenditure Amount	Percent of Total Portfolio Expenditures
Agricultural	Administrative	$45,124	0.2%	$71,914	0.8%
	Direct Implementation (Non-Incentive)	$303,626	1.6%	$226,586	2.4%
	Direct Implementation Incentive	$76,965	0.4%	$0	0.0%
	Marketing, Education and Outreach	$15,000	0.1%	$23	0.0%
	Sector Total	$440,714	2.4%	$298,523	3.2%
Commercial	Administrative	$1,283,751	6.9%	$150,134	1.6%
	Direct Implementation (Non-Incentive)	$3,420,029	18.3%	$3,282,453	35.4%
	Direct Implementation Incentive	$4,477,402	23.9%	$43,507	0.5%
	Marketing, Education and Outreach	$35,000	0.2%	$1,040	0.0%
	Sector Total	$9,216,182	49.2%	$3,477,134	37.5%
Cross-Cutting	Administrative	$27,911	0.1%	$28,747	0.3%
	Direct Implementation (Non-Incentive)	$1,931,034	10.3%	$834,655	9.0%
	Direct Implementation Incentive	$0	0.0%	$0	0.0%
	Marketing, Education and Outreach	$0	0.0%	$0	0.0%
	Sector Total	$1,958,945	10.5%	$863,402	9.3%
Industrial	Administrative	$54,063	0.3%	$71,914	0.8%
	Direct Implementation (Non-Incentive)	$466,476	2.5%	$226,586	2.4%
	Direct Implementation Incentive	$243,502	1.3%	$12,163	0.1%
	Marketing, Education and Outreach	$15,000	0.1%	$23	0.0%
	Sector Total	$779,041	4.2%	$310,686	3.4%
Residential	Administrative	$133,496	0.7%	$126,132	1.4%
	Direct Implementation (Non-Incentive)	$2,064,977	11.0%	$1,304,742	14.1%
	Direct Implementation Incentive	$3,311,416	17.7%	$2,368,260	25.6%
	Marketing, Education and Outreach	$75,000	0.4%	$118,641	1.3%
	Sector Total	$5,584,890	29.8%	$3,917,775	42.3%

EM&V	EM&V	$307,090	1.6%	$154,433	1.7%
	Sector Total	$307,090	1.6%	$154,433	1.7%
Portfolio Support	Administrative	$445,600	2.4%	$245,189	2.6%
	Sector Total	$445,600	2.4%	$245,189	2.6%
Portfolio Total		**$18,732,461**	**100.0%**	**$9,267,142**	**100.0%**

Segment-level[14]

Segment	Budget Category	Authorized Budget Amount	Percent of Total Portfolio Budget	Expenditure Amount	Percent of Total Portfolio Expenditures
Equity	Administrative	$193,326	1.0%	$194,093	2.0%
	Direct Implementation (Non-Incentive)	$2,411,296	13.1%	$2,620,035	27.2%
	Direct Implementation Incentive	$2,130,596	11.6%	$2,354,260	24.5%
	Marketing, Education and Outreach	$40,000	0.2%	$119,635	1.2%
	Segment Total	$4,775,218	25.9%	$5,288,023	54.9%
Market Support	Administrative	$51,677	0.3%	$47,848	0.5%
	Direct Implementation (Non-Incentive)	$931,034	5.1%	$889,319	9.2%
	Direct Implementation Incentive	$0	0.0%	$0	0.0%
	Marketing, Education and Outreach	$0	0.0%	$0	0.0%
	Segment Total	$982,711	5.3%	$937,167	9.7%
Resource	Administrative	$1,744,942	9.5%	$452,088	4.7%
	Direct Implementation (Non-Incentive)	$4,843,811	26.3%	$2,878,074	29.9%
	Direct Implementation Incentive	$5,978,689	32.4%	$69,670	0.7%
	Marketing, Education and Outreach	$100,000	0.5%	$92	0.0%
	Segment Total	$12,667,443	68.7%	$3,399,925	35.3%
Portfolio Total		**$18,425,372**	**100.0%**	**$9,625,114**	**100.0%**

[14] Table excludes EM&V, which is not a segment.

Portfolio-level

Portfolio	Budget Category	Authorized Budget Amount	Percent of Total Portfolio Budget	Expenditure Amount	Percent of Total Portfolio Expenditures
Portfolio	Administrative	$1,989,945	11%	$768,262	8%
	Direct Implementation (Non-Incentive)	$8,186,141	44%	$6,387,427	65%
	Direct Implementation Incentive	$8,109,285	43%	$2,423,931	25%
	Marketing, Education and Outreach	$140,000	1%	$119,727	1%
	EM&V	$307,090	2%	$154,433	2%
Portfolio Total		**$18,732,461**	**100.0%**	**$9,853,780**	**100.0%**

Energy Savings

Program-level

PrgID	Program Name	Savings Category	Net MW Savings	Net GWh Savings	Net MM Therms Savings
MCE01	MFES	Installed Program Savings	0.0004	-0.1340	0.0185
		Adopted Goals	0.0016	-0.0422	0.0224
		Goal Attainment Percentage	25.7%	317.4%	82.6%
MCE01c	MF SEM	Installed Program Savings	0.0249	0.1957	0.0019
		Adopted Goals	0.0000	0.6000	0.0198
		Goal Attainment Percentage	0.0%	32.6%	9.7%
MCE01d	Res EE Market	Installed Program Savings	0.0002	-0.0229	0.0030
		Adopted Goals	-0.0408	-0.1973	0.0992
		Goal Attainment Percentage	-0.5%	11.6%	3.0%
MCE02a	Com Deemed	Installed Program Savings	0.0000	0.0000	0.0048
		Adopted Goals	0.0606	0.3047	0.0362
		Goal Attainment Percentage	0.0%	0.0%	13.2%
MCE02b	Com Custom	Installed Program Savings	0.0045	0.0274	-0.0001
		Adopted Goals	0.1136	1.8686	0.0231
		Goal Attainment Percentage	4.0%	1.5%	-0.5%
MCE02c	Com SEM	Installed Program Savings	0.0742	0.4641	0.0115
		Adopted Goals	0.0000	1.7822	0.0713
		Goal Attainment Percentage	0.0%	26.0%	16.1%
MCE02d	Com Flex Market	Installed Program Savings	0.1650	0.5230	0.0000
		Adopted Goals	2.8312	23.6835	-0.0434
		Goal Attainment Percentage	5.8%	2.2%	0.0%
MCE02e	Com SBEA	Installed Program Savings	0.0000	0.0000	0.0000
		Adopted Goals	0.0000	0.0000	0.0000
		Goal Attainment Percentage	0.0%	0.0%	0.0%
MCE08	SF HES	Installed Program Savings	0.0758	-0.0482	0.0378
		Adopted Goals	0.1012	-0.0278	0.0325
		Goal Attainment Percentage	74.9%	173.6%	116.1%
	Ind Deemed	Installed Program Savings	0.0000	0.0000	0.0000
		Adopted Goals	0.0197	0.0948	0.0036

MCE10a		Goal Attainment Percentage	0.0%	0.0%	0.0%
MCE10b	Ind Custom	Installed Program Savings	0.0000	0.0000	0.0000
		Adopted Goals	0.0068	0.2495	0.0327
		Goal Attainment Percentage	0.0%	0.0%	0.0%
MCE10c	Ind SEM	Installed Program Savings	0.0088	0.0627	0.0164
		Adopted Goals	0.0000	0.5952	0.0439
		Goal Attainment Percentage	0.0%	10.5%	37.3%
MCE11a	Ag Deemed	Installed Program Savings	0.0000	0.0000	0.0000
		Adopted Goals	0.0000	0.0877	0.0000
		Goal Attainment Percentage	0.0%	0.0%	0.0%
MCE11b	Ag Custom	Installed Program Savings	0.0000	0.0000	0.0000
		Adopted Goals	0.0110	0.0551	0.0021
		Goal Attainment Percentage	0.0%	0.0%	0.0%
MCE11c	Ag SEM	Installed Program Savings	0.0000	0.0000	0.0000
		Adopted Goals	0.0000	0.5500	0.0311
		Goal Attainment Percentage	0.0%	0.0%	0.0%

Sector-level

Sector	Savings Category	Net MW Savings	Net GWh Savings	Net MM Therms Savings
Agricultural	Installed Program Savings	0.0000	0.0000	0.0000
	Adopted Goals	0.0110	0.6927	0.0332
	Goal Attainment Percentage	0.0%	0.0%	0.0%
Commercial	Installed Program Savings	0.2438	1.0144	0.0162
	Adopted Goals	3.0054	27.6390	0.0872
	Goal Attainment Percentage	8.1%	3.7%	18.6%
Cross-Cutting	Installed Program Savings	0.0000	0.0000	0.0000
	Adopted Goals	0.0000	0.0000	0.0000
	Goal Attainment Percentage	0.0%	0.0%	0.0%
Industrial	Installed Program Savings	0.0088	0.0627	0.0164
	Adopted Goals	0.0265	0.9395	0.0802
	Goal Attainment Percentage	33.1%	6.7%	20.4%
	Installed Program Savings	0.1013	-0.0094	0.0612
	Adopted Goals	0.0621	0.3327	0.1739

Residential	Goal Attainment Percentage	163.1%	-2.8%	35.2%
Portfolio Support	Installed Program Savings	0.0000	0.0000	0.0000
	Adopted Goals	0.0000	0.0000	0.0000
	Goal Attainment Percentage	0.0%	0.0%	0.0%

Segment-level

Segment	Savings Category	Net MW Savings	Net GWh Savings	Net MM Therms Savings
Equity	Installed Program Savings	0.0762	-0.1822	0.0563
	Adopted Goals	0.1029	-0.0700	0.0549
	Goal Attainment Percentage	74.1%	260.3%	102.4%
Market Support	Installed Program Savings	0.0000	0.0000	0.0000
	Adopted Goals	0.0000	0.0000	0.0000
	Goal Attainment Percentage	0.0%	0.0%	0.0%
Resource	Installed Program Savings	0.2776	1.2498	0.0374
	Adopted Goals	3.0022	29.6739	0.3195
	Goal Attainment Percentage	9.2%	4.2%	11.7%

Portfolio-level

Portfolio	Savings Category	Net MW Savings	Net GWh Savings	Net MM Therms Savings
Portfolio	Installed Program Savings	0.3538	1.0677	0.0937
	Adopted Goals	3.1051	29.6039	0.3745
	Goal Attainment Percentage	11.4%	3.6%	25.0%

TSB and Cost-Effectiveness

Program-level

PrgID	Program Name	Net TSB	Total Benefits (TRC/PAC)	Total TRC Cost	TRC Ratio	Total PAC Cost	PAC Ratio
MCE01	Multifamily Energy Savings Equity	$196,436	$410,486	$1,203,800	0.34	$1,182,262	0.35
MCE01c	Multifamily Strategic Energy Management	$80,173	$80,173	$175,040	0.46	$113,958	0.70
MCE01d	Residential Flex Market	$55,356	$55,356	$238,649	0.23	$192,092	0.29
MCE02a	Com Deemed	$62,857	$62,857	$160,151	0.39	$156,752	0.40
MCE02b	Com Custom	$8,747	$8,747	$163,118	0.05	$148,785	0.06
MCE02c	Com SEM	$320,271	$320,271	$209,156	1.53	$128,196	2.50
MCE02d	Commercial Flex Market	$81,021	$81,021	$2,675,767	0.03	$1,782,376	0.05
MCE02e	Com SBEA	$0	$0	$1,260,077	0.00	$1,260,077	0.00
MCE08	Home Energy Savings Equity	$1,050,513	$1,199,529	$2,809,580	0.43	$2,723,237	0.44
MCE10a	Ind Deemed	$0	$0	$99,508	0.00	$99,508	0.00
MCE10b	Ind Custom	$0	$0	$99,508	0.00	$99,508	0.00
MCE10c	Ind SEM	$146,668	$146,668	$136,143	1.08	$111,671	1.31
MCE11a	Ag Deemed	$0	$0	$99,508	0.00	$99,508	0.00
MCE11b	Ag Custom	$0	$0	$99,508	0.00	$99,508	0.00
MCE11c	Ag SEM	$0	$0	$99,508	0.00	$99,508	0.00
MCE16	Green Workforce Pathways	$0	$0	$863,402	0.00	$863,402	0.00
MCE98	MCE EM&V	$0	$0	$228,666	0.00	$228,666	0.00
MCE101-Equity-PS	Equity Portfolio Support	$0	$0	$416,220	0.00	$416,220	0.00
MCE101-MS-PS	Market Support Portfolio Support	$0	$0	$73,764	0.00	$73,764	0.00
MCE101-RA-PS	Resource Portfolio Support	$0	$0	$267,608	0.00	$267,608	0.00

Sector-level

Sector	Net TSB	Total Benefits (TRC/PAC)	Total TRC Cost	TRC Ratio	Total PAC Cost	PAC Ratio
Agricultural	$0	$0	$298,523	0.00	$298,523	0.00
Commercial	$472,897	$472,897	$4,468,270	0.11	$3,476,187	0.14
Cross-Cutting	$0	$0	$863,402	0.00	$863,402	0.00
Industrial	$146,668	$146,668	$335,159	0.44	$310,686	0.47
Residential	$1,382,478	$1,745,544	$4,427,068	0.39	$4,211,549	0.41

Portfolio Support	$0	$0	$757,593	0.00	$757,593	0.00

Segment-level

Segment	Net TSB	Total Benefits (TRC/PAC)	Total TRC Cost	TRC Ratio	Total PAC Cost	PAC Ratio
Equity	$1,610,015	$1,610,015	$5,689,677	0.28	$5,581,797	0.29
Market Support	$0	$0	$937,167	0.00	$937,167	0.00
Resource	$755,093	$755,093	$4,523,172	0.17	$3,398,977	0.22

Portfolio-level

Portfolio	Net TSB	Total Benefits (TRC/PAC)	Total TRC Cost	TRC Ratio	Total PAC Cost	PAC Ratio
Portfolio	$2,002,042	$2,365,108	$11,378,682	0.21	$10,146,607	0.23

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ORDERING IMMEDIATE IMPROVEMENTS TO THE CALIFORNIA CLIMATE CREDIT TO LOWER ELECTRIC AND GAS BILLS

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April 15, 2026

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends the Proposed Decision be revised to:

- Require comprehensive bill data be provided from each of the large IOUs by January 31, 2027, to evaluate the impacts of Climate Credit timing changes;
- Defer Phase 1B decisions until such data is available and analyzed; and
- Revise the Proposed Decision to incorporate CCA participation and neutral, standardized communications requirements, consistent with CalCCA's prior recommendations.

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ORDERING IMMEDIATE IMPROVEMENTS TO THE CALIFORNIA CLIMATE CREDIT TO LOWER ELECTRIC AND GAS BILLS

The California Community Choice Association[2] (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[3] on the proposed *Decision Ordering Immediate Improvements* to *the California Climate Credit to Lower Electric and Gas Bills* [4] (Proposed Decision), dated March 26, 2026.

I. INTRODUCTION

As CalCCA stated in its Opening Comments[5] on the Scoping Ruling,[6] California is in the midst of a well-documented affordability crisis, with energy bills representing a significant and

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

[3] *State of California Public Utilities Commission, Rules of Practice and Procedure, California Code of Regulations Title 20, Division 1, Chapter 1* (May 2021).

[4] Proposed *Decision Ordering Immediate Improvements* to *the California Climate Credit to Lower Electric and Gas Bills*, Rulemaking (R.) 25-07-013 (Mar. 26, 2026).

[5] *California Community Choice Association's Opening Comments on Assigned Commissioner's Scoping Memo and Ruling*, R.25-07-013 (Mar. 2, 2026) (CalCCA Scoping Ruling Opening Comments).

[6] *Assigned Commissioner's Scoping Memo and Ruling*, R.25-07-013 (Feb. 3, 2026) (Scoping Ruling).

growing burden for households across the state.[7] In this context, the Climate Credit remains an important, albeit limited, tool contributing to bill relief. As CalCCA has consistently emphasized, maximizing the effectiveness of that tool requires careful, data-driven policymaking grounded in a complete understanding of how customers experience their bills.[8]

Instead, the Proposed Decision requires Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, the IOUs), to adjust the months of distribution of the Climate Credit starting in 2026 to August and September (from April and October). The Proposed Decision relies on the same reasoning underlying the pause – "we must remain focused on the probable greater good."[9] Under that standard, the Proposed Decision may achieve that goal. But the Climate Credit is supposed to be a benefit for *all* residential customers in California, not for *most*. Before additional changes are made, this proceeding should endeavor to understand the impact of the Proposed Decision's changes, including on customers who don't live in cooling-dominant regions. Analysis is also necessary to understand how the Climate Credit interacts with other changes such as the Base Services Charge (BSC), that may provide higher bills in previously low use, low bill months. Further, the Commission must ensure the communication of those changes to *all* customers, from a neutral standpoint free from any bias from utility marketing.

In summary, CalCCA recommends that the Commission:

- Require comprehensive bill data be provided from each of the large IOUs by January 31, 2027, to evaluate the impacts of Climate Credit timing changes;

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7 CalCCA Scoping Ruling Opening Comments, at 1–2.

8 *Id*. at 9–10.

9 Proposed Decision, at 19 (citing D.26-03-013, at 16). Note that for small and multi-jurisdictional electric utilities the remaining residential electric credit will be distributed in November 2026 and October and November starting in 2027. The residential gas Climate Credit will be moved from April to February in 2027.

- Defer Phase 1B decisions until such data is available and analyzed; and

- Revise the Proposed Decision to incorporate community choice aggregator (CCA) participation and neutral, standardized communications requirements, consistent with CalCCA's prior recommendations.

II. THE FINAL DECISION SHOULD INCLUDE A REQUIREMENT FOR COMPREHENSIVE ANALYSIS OF ITS CHANGES PRIOR TO MOVING FORWARD WITH PHASE 1B TO ENSURE SECTION 748.5(a)(3)'S REQUIREMENT THAT ALL CUSTOMERS ARE BENEFITTED IS MET

CalCCA's Opening Comments emphasized that the proposed timing changes were speculative and unsupported by record evidence demonstrating improved affordability outcomes.[10] CalCCA specifically identified several unanswered questions that remain unresolved in the Proposed Decision, including:

- Does moving the Climate Credit to summer-peaking months adequately protect customers in winter-peaking areas?

- Do the increased administrative costs and operational inefficiencies associated with moving the Climate Credit provide a net benefit in terms of affordability?

- Is pausing the Climate Credit to later in the year instead of any earlier distribution better for customers from a time value of money perspective?

- How will customer confusion with an interim and then potentially different permanent change to the timing, eligibility, and number of distributions impact customers?[5]

The Proposed Decision acknowledges regional variability and competing proposals in the record but nonetheless adopts a uniform statewide approach based primarily on *average* seasonal trends,[6] arguing that the changes "are most likely to benefit more customers' affordability than does the status quo."[11] However, that is not the statutory directive under Public Utilities Code

[10] CalCCA Scoping Ruling Opening Comments, at 4.
[11] Proposed Decision, at 20.

section 748.5(a)(3),[12] which clearly requires that Climate Credit distributions maximize affordability for *all* customers, not merely for the average or majority.

At the same time, as CalCCA previously explained, section 748.5(a)(3) does not require the Commission to take *immediate* action absent a sufficient record.[13] Rather, the Commission could, and should, have maintained the status quo while developing a more robust evidentiary record to ensure that any changes truly maximize affordability for all customers. It may be true that fewer customers will be worse off under the change to August and September than would have been if the credit had stayed in April and October, as the Proposed Decision[14]. However, what about the acknowledged minority of customers that it will not be most beneficial for? The record also does not demonstrate that it will not be *worse* for them. If section 748.5(a)(3) is going to be used as the justification for the need to make immediate changes, then the statute must truly be followed and reflect an outcome that considers *all* customers.

Even if the Proposed Decision is adopted, the Commission must begin a careful process of considering the impacts of both the April pause, the fall shift of the Climate Credit distribution timing to August and September, prior to moving forward with additional modifications. The August and September distributions will now occur concurrently with other significant changes to customer bills, including the introduction of the BSC. The combined effects of these changes are not yet understood. For example, customers with historically low usage may experience higher or differently timed bill impacts under the new rate structure, potentially altering when affordability challenges arise.

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

[13] CalCCA Scoping Ruling Opening Comments, at 10-11.

[14] Proposed Decision, at 20.

Accordingly, the Commission should refrain from making further changes in Phase 1B until the impacts of the Phase 1A decisions are fully understood. CalCCA therefore recommends that each large IOU be required to file comprehensive, anonymized bill data by January 31, 2027. This data will enable parties and the Commission to evaluate the real-world impacts of the timing changes and the BSC, including, but not limited to, the impact on various climate zones. This will ensure that future decisions are informed by a complete record that reflects the experiences of all customers.

III. THE PROPOSED DECISION FAILS TO ADDRESS CALCCA'S RECOMMENDATIONS ON CCA INCLUSION AND NEUTRAL COMMUNICATIONS

CalCCA has consistently raised concerns regarding customer confusion and inaccurate messaging associated with both the pause of the April Climate Credit and the subsequent changes to the distribution timing. In its prior comments, CalCCA emphasized the need for coordinated and standardized messaging that maintains competitive neutrality across all load-serving entities, including CCAs.[15] Other parties, including EDF and Cal Advocates, likewise identified the significant risk of customer confusion resulting from rushed or inconsistent communications.[16]

Unfortunately, the Proposed Decision does not sufficiently address or acknowledge these concerns. While CalCCA appreciates the Commission's recognition and revisions in D.26-03-013[17] to "better reflect that the Climate Credit is distributed *by* utilities, but the money

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[15] CalCCA Scoping Ruling Opening Comments, at 8-9; *California Community Choice Association's Reply Comments on Assigned Commissioner's Scoping Memo and Ruling*, R.25-07-013 (Mar. 9, 2026) (CalCCA Scoping Ruling Reply Comments), at 6.

[16] CalCCA Scoping Ruling Reply Comments, at 2-3 (citing EDF and Cal Advocates comments).

[17] D.26-03-013, *Decision Pausing the 2026 Residential Climate Credits Distributed by the Large Electric Utilities*, R.25-07-013 (Mar. 19, 2026).

is not *from* the utilities," recent utility communications demonstrate that these principles are not being consistently implemented in practice.

For example, PG&E recently included notice of the credit in a customer email prominently labeled "Our fifth electric rate decrease in two years," accompanied by direction at the bottom of that email to "Learn how we're lowering prices" directly below the acknowledgement of the section titled "California Climate Credit."[18] That section also began with a bold heading of "More savings" without including any information indicating the source of the funds. This type of messaging risks conflating the Climate Credit with utility action and may lead customers to incorrectly believe that the benefit is provided by the IOU.

The Proposed Decision dismisses concerns regarding customer confusion, in part, based on findings that customers have low awareness of the Climate Credit.[19] However, this only heightens the need for clear, accurate, and neutral communications. If customers are unfamiliar with the Climate Credit, then pairing information about the credit with utility marketing language, such as claims of lowering rates or providing savings, creates a substantial risk that customers will misattribute the source of the benefit.

Although communications regarding the April credit have already occurred, there remains sufficient time before the August and September distributions to implement improved outreach practices. Meaningful coordination with CCAs is both feasible and necessary to ensure accurate and consistent messaging.

Accordingly, consistent with its prior filings, CalCCA recommends that the Proposed Decision be revised to: (1) require meaningful CCA involvement in the development and review of Climate Credit communications; and (2) ensure that all communications are neutral, factual,

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[18] PG&E Customer Email (Apr. 1, 2026).

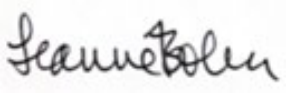
[19] Proposed Decision, at 19.

and free of utility marketing, consistent with the principle that Climate Credit funds are not a utility benefit.

IV. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and respectfully 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,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

April 15, 2026

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ORDERING IMMEDIATE IMPROVEMENTS TO THE CALIFORNIA CLIMATE CREDIT TO LOWER ELECTRIC AND GAS BILLS

PROPOSED CHANGES TO FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS

Proposed text deletions show as ~~**bold and strikethrough**~~
Proposed text additions show as **bold and underlined**

FINDINGS OF FACT

Climate Credit outreach should remain neutral and reflect that the Climate Credit is distributed by utilities, but the funds are not a utility-provided benefit.

CONCLUSIONS OF LAW

It is reasonable to require the large electric utilities to work with Community Choice Aggregators (CCAs) on outreach plans and messaging to ensure communications remain competitively neutral and limit customer confusion.

ORDERING PARAGRAPHS

Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall file comprehensive, anonymized customer bill data with the Commission and serve it on all parties no later than January 31, 2027, sufficient to evaluate the impacts of the adopted Climate Credit timing changes, including interactions with other rate design elements.

Phase 1B of this proceeding shall not result in any additional substantive decisions modifying the Climate Credit until the data required in Ordering Paragraph 2 has been filed and adequately reviewed by the Commission and parties.

Add to OP 4:
(f) Coordinate with Community Choice Aggregators (CCAs) in the development and review of all Climate Credit-related customer communications.
(g) Ensure all Climate Credit communications are neutral, factual, and standardized across load-serving entities, and shall not include utility marketing or promotional content, consistent with the principle that Climate Credit funds are not a utility-provided benefit.

New Order:

FILED
04/20/26
04:59 PM
R2106017

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 COMMENTS IN RESPONSE TO THE ASSIGNED COMMISSIONER'S RULING ON TRACK 1 AND TRACK 2 DISTRIBUTED ENERGY RESOURCES ORCHESTRATION

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April 20, 2026

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends that the Commission:

- Defer the development of an IOU-led DER orchestration framework and expand the scope to evaluate all DSO models as discussed in the OIR to ensure any decision on the DSO framework is based on an adequate record; and

- Adopt the following DSO foundational guiding principles in addition to those set forth in the Ruling before deciding on a DSO framework: (1) nondiscriminatory market access, operations, and dispatch; (2) independent monitoring and oversight of the DSO and market functions; (3) optimization of existing distribution grid capacity before authorization of capital investments; (4) competitive neutrality of the DSO and marketplace operator; (5) fair compensation for DER flexibility services; and (6) timely access to accurate customer usage, DER, integration capacity analysis, and grid data.

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS IN RESPONSE TO THE ASSIGNED COMMISSIONER'S RULING ON TRACK 1 AND TRACK 2 DISTRIBUTED ENERGY RESOURCES ORCHESTRATION

California Community Choice Association[2] (CalCCA) submits these comments pursuant to the *Assigned Commissioner's Ruling on Track 1 and Track 2 Energy Resources Orchestration* [3] (Ruling), dated March 23, 2026, and the *Email Ruling Granting Request for Extension on Comments and Workshop*,[4] dated April 3, 2026. The Ruling seeks responses to questions regarding an approach for developing a Distributed Energy Resources (DER) Orchestration Framework.

I. INTRODUCTION

The development of an effective, coordinated approach to DER operations offers significant opportunities to reduce costs, lower bills, improve reliability, avoid expensive grid investments, minimize energization times, and achieve electrification goals. California has

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

[3] *Assigned Commissioner's Ruling on Track 1 and Track 2 Distributed Energy Resources Orchestration*, Rulemaking (R.) 21-06-017 (Mar. 23, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K997/602997407.PDF.

[4] *Email Ruling Granting Request for Extension on Comments and Workshop*, R.21-06-017 (Apr. 3, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M603/K941/603941311.PDF.

experienced tremendous growth in the adoption of behind-the-meter DERs, particularly electric vehicles, battery energy storage systems, and intelligent devices. Harnessed effectively, these resources can provide valuable services to optimize existing grid capacity, improve reliability, and reduce the need for costly grid upgrades. The Ruling seeks Party input on a framework for a distribution system operator (DSO) to orchestrate DERs to accomplish these objectives and proposes a set of guiding principles to shape this framework. CalCCA supports many of the DSO operational needs and priority areas identified in the Ruling.

Significantly, however, CalCCA is concerned about the Ruling's direction to advance the DSO led through the investor-owned utilities (IOU), given that no Decision has been adopted and no record has been developed to identify whether IOUs should be considered the default option for the DSO function of DER orchestration. Until the Commission develops an adequate record regarding DSO options, including examining other independent DSO options, the focus should not be directly on developing the IOU-led DER Orchestration model, but rather should be on the foundational principles and necessities required to ensure all DER participants can transparently, effectively, and equitably engage in the DSO framework.

In addition to responding to the Ruling questions, CalCCA first provides general comments and recommendations herein on the proposed framework. As set forth below, CalCCA recommends that the Commission:

- Defer the development of an IOU-led DER orchestration framework and expand the scope to evaluate all DSO models as discussed in the Order Instituting Rulemaking (OIR) for this proceeding[5] to ensure any decision on the DSO framework is based on an adequate record; and

[5] *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future* (OIR), R.21-06-017 (July 2, 2021), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K664/390664433.PDF.

- Adopt the following DSO foundational guiding principles in addition to those set forth in the Ruling before deciding on a DSO framework: (1) nondiscriminatory market access, operations, and dispatch; (2) independent monitoring and oversight of the DSO and market functions; (3) optimization of existing distribution grid capacity before authorization of capital investments; (4) competitive neutrality of the DSO and marketplace operator; (5) fair compensation for DER flexibility services; and (6) timely access to accurate customer usage, DER, integration capacity analysis, and grid data.

II. THE COMMISSION SHOULD DEFER THE DEVELOPMENT OF AN IOU-LED DER ORCHESTRATION FRAMEWORK AND EXPAND THE SCOPE TO EVALUATE ALL DSO MODELS AS DISCUSSED IN THE OIR TO ENSURE ANY DECISION ON THE DSO FRAMEWORK IS BASED ON AN ADEQUATE RECORD

The Commission's direction to move forward with the exploration of IOU-led DSO orchestration wrongly assumes that other DSO models have been adequately considered in this proceeding, despite the OIR's direction to do so. While Public Utilities Code section 399.2 gives IOUs the authority to operate the distribution grid, it does not extend that authority to the orchestration and dispatch of customer- and non-IOU-owned DERs on the distribution grid.[6] Nor has there been any Commission decision that the IOUs should perform the DER orchestration function of a DSO. Therefore, instead of continuing to assume IOUs will lead DER orchestration, the Commission must continue to build the record for establishing the DSO framework through workshops and party comment opportunities before deciding on the entity responsible for the implementation of the adopted framework and various DSO functions.

As set forth in more detail below, the OIR and a subsequent Ruling[7] in this proceeding highlighted concerns about the conflict of interest inherent in the IOU business model. Parties to the proceeding have similarly raised concerns, as summarized below, about potential conflicts of

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[6] *See* Cal. Pub. Util. Code § 399.2. All section references herein are to the California Public Utilities Code unless otherwise specified.

[7] *Administrative Law Judge's Ruling Seeking Comments Regarding Future Grid Study (FGS) Report* (FGS Ruling), R.21-06-017 (Oct. 17, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M543/K421/543421872.PDF.

interest arising from IOUs serving as the DSO, including during the Future Grid Workshop series and in comments. There are also test cases that should be further explored in this proceeding, particularly regarding the significant growth in the number and trade volume of flexibility marketplaces, such as in the United Kingdom (UK). As discussed in greater detail below, the Commission should continue to build the record in the proceeding before directing the development of a DSO framework.

A. The Commission and Parties Have Identified Significant Unresolved Concerns Over the Potential Conflict of Interest for IOUs Serving as the DSO

The Ruling presents an approach to developing a DSO framework in which the IOUs will function as sole DSOs and orchestrate DERs. However, the Ruling fails to direct the evaluation of alternative DSO frameworks and unjustifiably assumes the IOUs will serve all DSO roles, including the DER orchestration function. The record in the proceeding includes multiple unaddressed concerns raised by the Commission and by parties about the inherent conflict of interest built into the existing IOU business model, which prioritizes capital investments over procuring DER flexibility services. For example, the OIR noted these concerns, stating:

> [t]he current cost recovery and investment structures for electric distribution systems focuses on large capital investments. *A high-penetration DER structure could reduce overall IOU rates of return.* For an IOU-administered DSO to be successful, performance incentives not tied to capital investments may be needed, or there may be a need for a third-party DSO administrator.[8]

The DNV GL Overview of DSO Models study (DNV Overview), included as Appendix B in the OIR, illustrates features of different DSO models, including IOU-led and third-party-led DSOs, and highlights the inherent IOU bias towards capital investments:

[8] OIR, at 11-12 (emphasis added).

> . . . it is important to note that utilities primarily have the obligation to serve and they are optimized for managing grid stability and operations to deliver energy to customers. They also are incentivized to earn a rate of return from capital investments, instead of procuring DER services.[9]

Presumably addressing the need for incentive mechanisms to mitigate these identified conflicts of interest, the Ruling seeks input on a potential valuation framework and a shared savings mechanism (SSM). However, the Ruling fails to address the extent to which the Commission expects these measures to mitigate the IOUs' incentive to make capital investments and instead procure DER services.

The November 15, 2021, Assigned Commissioner's Scoping Memo and Ruling appropriately scoped these very issues, asking:

> 1. How do alternative DSO models compare in their ability to plan and operate a high DER grid, unlock economic opportunities for DERs to provide grid services, limit market power, reduce ratepayer costs, increase equity, support grid resiliency, and meet State policy objectives? [and] 2. Should the Utilities be incentivized to cost-effectively prepare for widespread DER deployments? If so, how?[10]

The Commission hosted an initial workshop titled "Evaluating Alternative Distribution System Operator Models for California,"[11] based on a Gridworks white paper[12] of the same title. However, a 2023 Amended Scoping Ruling abruptly amended the Track 2 scoping questions to

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[9] OIR, Appendix B, at 82, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M392/K348/392348813.pdf.

[10] *Assigned Commissioner's Scoping Memo and Ruling*, R.21-06-017 (Nov. 11, 2021), at 6, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M422/K949/422949772.PDF.

[11] Gridworks Workshop Summary, *Evaluating Alternative DSO Models for California Workshop*, R.21-06-017 (May 2, 2022), https://gridworks.org/wp-content/uploads/2022/07/Gridworks-May-3-DSO-Workshop-Summary-final.pdf.

[12] Gridworks Whitepaper, *Evaluating Alternative Distribution System Operator Models for California* (Mar. 2022), https://gridworks.org/wp-content/uploads/2022/03/Evaluating-Alternative-DSO-Models-for-California.docx.pdf.

assume the IOUs would serve as the default DSO.[13] Notably, there was no opportunity for non-IOU parties to comment on the amended Track 2 scoping questions. The Ruling omits this critical procedural history, and the record lacks any explanation for the amended scope.

The Ruling is also silent on other DSO frameworks that could reduce or eliminate the inherent conflict of interest in an IOU-led DSO framework, despite information presented during the FGS Workshop series and in party comments on the FGS Report on alternative models. The record in the proceeding demonstrates that there is significant disagreement among parties on the appropriate framework for the DSO, as evidenced in the FGS Ruling:

> Following Workshop 1, the workshop series highlighted a diverging approach to long-term visions for a High DER Future between the IOUs' top-down "grid orchestration" approach where DSOs are central in coordinating DERs and the bottom-up, open-access vision recommended by other stakeholders.[14]

Among the parties strongly supporting an open-access approach to the distribution grid in its Comments on the FGS Ruling, CalCCA argues that the "top-down, grid orchestration approach favored by the IOUs perpetuates IOU market control, potentially limiting the pool of available DERs to support grid operations and offset grid investments."[15] Other parties also support exploring alternative DSO models in their FGS Ruling Comments:

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[13] *Assigned Commissioner's Amended Scoping Memo and Ruling*, R.21-06-017 (Aug. 11, 2023), at 6-7, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M516/K786/516786462.PDF.

[14] FGS Ruling, at 5-6.

[15] *See, e.g.*, *CalCCA's Comments on Administrative Law Judge's Ruling Seeking Comments Regarding FGS Report* (CalCCA FGS Report Comments), R.21-06-017 (Dec. 6, 2024), at 3-5, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M548/K361/548361442.PDF.

- Green Power Institute: "Continuing IOU control of most aspects of DER grid operations may be unwise given abundant evidence that IOUs have misaligned incentives to create the future grid vision that GPI and other parties have offered," and recommending a third-party DSO with "no financial stake in infrastructure investments and no incentive to favor utility-owned resources over customer or community-owned DERs" who would be better positioned to implement open access and neutrality while ensuring fair competition between all resources (owned by the utility, customers, or a community).[16]
- Utility Consumers' Action Network: "The regulated business model of a [Distribution Network Operator], which derives profit from network investments, directly conflicts with the need to promulgate markets and dynamic price signals that enable DERs to lower peak loads and provide grid services as an alternative to network investments. To keep costs manageable for ratepayers and maintain rates at a level that supports continued electrification in a High DER Future, other organized electricity markets have addressed this financial disincentive by evolving regulated utility business models in ways that are intended to ensure a fair return while also incentivizing utilities to operate efficiently."[17]
- The Climate Center, Center for Biological Diversity, Clean Coalition, Microgrid Resources Coalition, Green Power Institute, and 350 Bay Area: "the need to upgrade distribution operations should be based to a large extent on our expectations about DER growth and participation. The Joint Parties believe that to unlock the greatest benefits from DERs, including but not limited to all the participation modes identified in the section on animating distribution level markets, it is necessary to shift from a top-down to a bottom-up resource planning approach."[18]

An open-access grid requires a market to match flexible capacity needs with flexible resource providers. The proposed IOU-led DSO framework will effectively have the IOUs serve as a marketplace operator, while retaining ownership and control of the distribution grid and deciding which resources will be selected to provide flexibility services. Because of the inherent

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[16] *Green Power Institute Opening Comments on FGS Report*, R.21-06-017 (Dec. 6, 2024), at 16, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M548/K362/548362230.PDF.

[17] *Comments of the Utility Consumers' Action Network (UCAN) on Administrative Law Judges' Ruling Seeking Comments Regarding FGS Report*, R.21-06-017 (Dec. 6, 2024), at 4-5, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M548/K362/548362344.PDF.

[18] *The Climate Center, Center for Biological Diversity, Clean Coalition, Microgrid Resources Coalition, Green Power Institute, and 350 Bay Area (the "Joint Parties") Opening Comments on the FGS*, R.21-06-017 (Dec. 6, 2024), at 10, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M549/K797/549797792.PDF.

bias created through an IOU-led DSO, the Commission must continue exploring alternative DSO frameworks.

B. An IOU-Led DSO Model Deviates from FERC Findings on Market Independence

In addition to conflict-of-interest concerns, an IOU-led DSO framework raises questions about market independence which has been addressed the Federal Energy Regulatory Commission (FERC) in its findings on regional transmission organizations (RTO) and independent system operators (ISO). The Commission should look to FERC's rulings on market independence for RTO/ISOs to guide its exploration of a DSO framework to ensure fair and open market access and avoid conflicts of interest or the ability for market participants to exert market power. Indeed, similar to dispatch of the transmission system, IOUs will have a vested interest in the outcome of DSO dispatch decisions because IOUs will presumably continue to own or contract with DERs. As such, IOUs have a vested interest in which resource(s) will be dispatched to meet grid needs. Even if an IOU does not have a resource available to meet a particular need, it still has a vested interest in dispatch decisions as a load-serving entity (LSE) in competition with other LSEs (*i.e.*, Electric Service Providers and community choice aggregators (CCA)).

In its Notice of Proposed Rulemaking[19] and Order 2000[20] regarding the RTOs and ISOs, FERC found that a market operator's independence can only be ensured by prohibiting a market participant from exerting control over the market. In FERC's view, "…an RTO must be independent of any entity whose economic or commercial interests could be significantly

[19] Notice of Proposed Rulemaking, *Regional Transmission Organizations*, 64 Fed. Reg. 31390 (June 10, 1999), https://www.govinfo.gov/content/pkg/FR-1999-06-10/pdf/99-12553.pdf.

[20] Regional Transmission Organizations, 65 Fed. Reg. 810 (Jan. 6, 2000), (to be codified at 18 C.F.R. pt. 35), https://www.ferc.gov/sites/default/files/2020-06/RM99-2-00K_1.pdf.

affected by the RTO's actions or decisions. Without such independence, it will be difficult for an RTO to act in a non-discriminatory manner."[21]

Such entities include electric energy buyers. FERC recognized "…that there may be circumstances where buyers of electric energy could buy a controlling interest in a for-profit RTO and manipulate its access and curtailment decisions to their advantage" and found that "[s]uch an outcome would clearly be inconsistent with the independence standard."[22] FERC therefore included in its definition of market participant, "any other entity that the Commission finds has economic or commercial interests that would be significantly affected by the RTO's actions or decisions." This definition enables FERC to consider whether buyers of electric energy or any other entity "could manipulate an RTO's decisions to the disadvantage of other RTO customers."[23]

The Commission should look to FERC's rulings on market independence for RTO/ISOs to guide its exploration of a DSO framework. Since DER Orchestration is primarily about curtailment decisions by participating entities or potential firm load curtailments, the IOU is inextricably linked to the outcomes of DSO decisions. The Commission must fully evaluate the design and implementation of the DER Orchestration framework to ensure that no entity can make decisions that result in unreasonable and uncompetitive outcomes.

Alternative DSO frameworks exist beyond just IOU-led or fully independent DSOs, including hybrid approaches in which the IOU retains ownership and operation of the distribution grid, while an independent entity operates the DSO function of a flexibility marketplace.[24] The

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21 Order 2000, at 195.
22 *Id.* at 196.
23 *Id*. at 196-197.
24 *See, e.g., Electricity North West, Piclo, & Electron Announce Partnership to Maximise Market Access for Flexibility* (Mar. 27, 2024), https://www.piclo.com/press-releases/electricity-north-west-piclo-

hybrid approaches require oversight to ensure open and fair market access, but can reduce potential market power and conflict-of-interest concerns with the IOUs. Given the competing considerations and the lack of an adequate record supporting a specific DSO structure, the Commission should continue to explore other DSO frameworks that minimize the IOUs' potential inequitable market power and conflict of interest through workshops and party comments.

C. Significant Changes in the Deployment of Flexibility Marketplaces Have Occurred Since the FGS Ruling

Much has changed since the DNV Overview was prepared, with the significant expansion of flexibility markets and marketplace operators in Great Britain, as well as flexibility market pilots in Europe, Australia, and the United States (US). The British demand flexibility market grew from 1.6 GW of flexibility services contracted in 2021[25] to 9 GW in 2025,[26] and at least two new marketplace operators announced partnerships with major DSOs in 2024.[27] The UK-based marketplace operator Piclo launched its Marketplace platform across the US in 2025 and

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electron-announce-partnership-to-maximise-market-access-for-flexibility#:~:text=Electricity%20North%20West%20is%20one,onboarding%20platform%20of%20their%20choice.

[25] Energy Networks Association, *Britain Breaks Network Flexibility Record with 45% More Contracted than All of 2020* (July 30, 2021), https://www.energynetworks.org/newsroom/britain-breaks-network-flexibility-record-with-45-percent-more-contracted-this-year-than-all-of-2020#:~:text=Britain%20breaks%20network%20flexibility%20record,%E2%80%93%20Energy%20Networks%20Association%20(ENA).

[26] Energy Networks Association, *GB Cements Status as World Leader in Energy Flexibility with Estimated £300m Savings for Billpayers* (June 26, 2025), https://www.energynetworks.org/newsroom/gb-cements-status-as-world-leader-in-energy-flexibility-with-estimated-gbp-300m-savings-for-bill-payers.

[27] *See*, *e.g.*, *Electricity North West Partners with Electron to Deliver Next Generation of Flexibility Markets Across Its Network* (Jun. 18, 2024), https://electron.net/electricity-north-west-partners-with-electron-to-deliver-next-generation-of-flexibility-markets-across-its-network/;
New Partnership Between UK Power Networks and EPEX SPOT Set to "Supercharge Flexibility Market" (Jan. 11, 2024), https://www.epexspot.com/en/news/new-partnership-between-uk-power-networks-and-epex-spot-set-supercharge-flexibility-market; and
Blake Clough Consulting, *DSO Flexibility Markets Transforming GB's Grid Economics* (Oct. 28, 2025), https://www.blakeclough.com/dso-flexibility-markets-transforming-gbs-grid-economics/.

claims to have over 250 flexibility service providers participating in its US, European, and Australian markets, representing more than 40 GW of flexible capacity.[28]

Given the significant growth in flexibility markets and DSOs since the FGS Workshop Report Ruling and comments, the Commission should host additional workshops to learn from various DSO frameworks and inform the discussion of a DSO framework for California.

III. THE COMMISSION SHOULD DEVELOP THE RECORD AND ESTABLISH DSO GUIDING PRINCIPLES BEFORE DECIDING ON THE DSO FRAMEWORK

The Commission should establish DSO guiding principles as a first step in building the record for a DSO framework. This record can then form the basis for evaluating DSO frameworks. Deciding on a set of guiding principles before selecting a DSO framework ensures it best meets the needs of ratepayers and stakeholders. These guiding principles should be applicable to any DSO framework, although additional framework-specific principles may be considered to ensure ratepayer/consumer protection, market integrity, and to account for unforeseen circumstances.

The Ruling identifies ten DSO guiding principles for consideration and comment, including:

- Ratepayer benefit and protection;
- Technology-neutral, performance-based;
- Locational and temporal value recognition;
- Efficient operation of the grid;
- Open access and Interoperability;
- Transparent participation pathways and compensation;
- Incremental, evidence-based implementation;
- Equity and customer protection;

[28] *Piclo Marketplace Launches US-Wide – Bringing Energy Markets Together with a Game-Changing Unified Platform for Buyers and Sellers* (Mar. 28, 2025), https://www.piclo.com/press-releases/piclo-marketplace-launches-us-wide.

- Cyber-secure and resilient; and
- Preventing double compensation.[29]

CalCCA supports the Commission's proposed guiding principles and offers the following additional principles, which, to some extent, overlap but further identify necessary components of the DSO framework:

- Nondiscriminatory market access, operations, and dispatch;
- Independent monitoring and oversight of the DSO and market functions;
- Optimization of existing distribution grid capacity before authorization of capital investments;
- Competitive neutrality of the DSO and marketplace operator;
- Fair compensation for flexibility services; and
- Timely access to accurate customer usage, DER, integration capacity analysis, and grid data.

These additional principles aim to mitigate potential conflicts of interest, prevent market manipulation, and ensure a level playing field for third-party-managed DERs. CCAs manage large portfolios of DERs through programs and tariffs, and some have launched or are planning to launch DERMS platforms to monitor and control DERs. The proposed additional guiding principles will enable CCA-managed DERs to participate in any future DER marketplace. The Commission should adopt these additional guiding principles, regardless of the DSO framework that is adopted.

IV. RESPONSES TO RULING QUESTIONS

The following responses to the Ruling questions are provided on the assumption that they do not apply only in the context of an IOU-led DSO framework. DER orchestration results from managing and sharing data, which occurs across all DSO frameworks. The responses below are therefore intended to apply to any DSO framework, unless otherwise indicated.

[29] Ruling at 7.

Ruling Section 3. IOU DSO-led DER Orchestration Initiation

1) What should some of the primary objectives of IOU DSO led DER orchestration be?

CalCCA recommends that the primary objectives of DER orchestration include:

- Delivering verifiable net benefits to ratepayers, including economic, societal, and equity benefits;
- Optimizing existing capacity on the distribution grid;
- Deferring or eliminating the need for IOU distribution infrastructure investments;
- Minimizing customer energization and DER interconnection times and costs;
- Ensuring open, non-discriminatory access for DERs owned or managed by customers, CCAs, and third-party aggregators;
- Creating and maintaining interoperability and transparent demand flexibility participation pathways;
- Ensuring independent monitoring, oversight, and enforcement of participation rules, performance metrics, and compensation/settlement functions;
- Ensuring timely access to accurate data to support participation of non-IOU managed DERs;
- Accurately identifying and valuing deferral opportunities and demand flexibility opportunities, and communicating these opportunities to flexibility providers;
- Providing transparent and fair compensation for flexibility services; and
- Increasing the deployment and utilization of DERs for flexibility services, including for low-income customers and disadvantaged communities.

2) What are the primary grid constraints that could be solved, or operational improvements that could be created, through implementation of a utility DSO-led DER orchestration?

DER orchestration, if properly and transparently designed and operated, can result in significant cost savings and reliability benefits for the distribution grid. Coordinated operation of customer-owned DERs helps optimize existing grid capacity, potentially deferring or eliminating the need for distribution system capital investments. DER orchestration can also free up capacity on constrained circuits, improving reliability and resiliency, reducing outages, and enabling new

loads to energize more quickly. These potential benefits can only be achieved if all customer-owned DERs are enabled and encouraged to provide flexibility services.

As stated in the OIR:

> In California, DSO functions, including distribution system planning and operations, are provided by the electric IOUs. As the market evolves into a high-penetration DER scenario, IOU roles will also evolve and there may be a need to consider different DSO roles. The term, "DSO," is often used in reference to conceptual models designed to efficiently operate distribution systems with high numbers of DERs. The various DSO models present alternative approaches to distribution system planning and operations that may help integrate DERs at least cost by increasing DER market opportunities and value capture while maintaining system safety and reliability.[30]

Any DSO framework must be structured to avoid bias and to ensure full, transparent access for all DER flexibility providers. This includes monitoring and oversight to provide a level playing field for flexibility providers and to prevent over-investment in the grid, and may require changes to an IOU's rate-of-return model. The Commission must continue to explore DSO frameworks to understand which functions must be performed by the IOUs and which are better suited to an independent marketplace operator or other entity.

3) What are appropriate valuation frameworks to quantify ratepayer value to potentially be unlocked through DER orchestration?

CalCCA does not propose a specific ratepayer valuation framework at this time but recommends that any such framework should quantify the potential ratepayer value enabled by DER orchestration, including societal and equity benefits. CalCCA recommends including the following elements when evaluating the benefits of customer-provided demand flexibility services:

- Recognition of customer ownership and investment in DER resources;
- Avoided or deferred infrastructure costs;

[30] OIR, at 11.

- Locational and temporal value provided by flexibility services;
- Impact on meeting electrification and greenhouse gas reduction goals;
- Reliability and resiliency improvements; and
- Societal and equity benefits.

An example the Commission should explore is the performance metrics and incentive frameworks established by the UK Office of Gas and Electricity Markets (Ofgem), which regulates DSOs. At least two DSOs operating in the UK have adopted methodologies to quantify societal benefits of their activities as part of their incentive frameworks.[31] The societal goals established include achieving net-zero goals, reducing bills, increasing participation by low-income and disadvantaged customers in flexibility markets, enhancing community resilience, and providing public health benefits from reduced emissions. While CalCCA does not yet take a position on the specific measures adopted under the Ofgem incentive framework, it encourages the Commission to include quantification of societal benefits as a part of the discussion of valuation frameworks.

4) **Should the Commission adopt the following set of guiding principles to shape the proposed IOUs' DER orchestration framework applications?**

- **Ratepayer benefit and protection**
- **Technology-neutral, performance-based**
- **Locational and temporal value recognition**
- **Efficient operation of the grid**
- **Open access and Interoperability**
- **Transparent participation pathways and compensation**
- **Incremental, evidence-based implementation**
- **Equity and customer protection**
- **Cyber-secure and resilient**
- **Preventing double compensation**

[31] *See* SP Electricity Northwest, *DSO Benefits Methodology* (2026), https://www.enwl.co.uk/globalassets/future-energy/dso/social-dso/benefits-docs/dso-benefits-methodology-2026.pdf, Scottish & Southern Electricity Networks, *SSEN Distribution DSO Benefit Methodology* (2024-2025), https://www.ssen.co.uk/globalassets/about-us/dso/publication--reports/ssen-dso-benefit-methodology-2025.pdf.

Should the Commission remove, modify, or clarify any of these guiding principles? Should the Commission add additional guiding principles? If the Commission adopts these guiding principles, should there be an opportunity to refine them in any proceeding reviewing IOU applications?

See CalCCA's discussion and recommendations regarding the Ruling's identified guiding principles in Section III, above.

5) **How can findings from the Electrification Impact Study Part 2 (EIS Part 2) conducted as part of Track 1 of this proceeding inform the DER Orchestration application content? For example, can findings from EIS Part 2 inform the identification of areas best suited for piloting DER orchestration?**

The findings from the EIS Part 2 can inform the location and design of pilot programs for DER orchestration but should not be the sole factor in determining which pilots to pursue. The EIS Part 2 reports represent the first attempt by the IOUs to study the impacts of electrification and model potential demand flexibility opportunities. Significant differences between the methodologies for modeling the secondary systems produced disparate results between the IOUs. Since most residential customers are on the secondary system, the EIS Part 2 results should not be relied on as the sole source for phasing or piloting DER orchestration.

a. **Should the IOUs consider the results from the EIS Part 2 studies to phase implementation of DER Orchestration? If so, how should the results from the equity and enhanced demand flexibility scenarios in the EIS Part 2 studies be considered?**

See CalCCA's response to Question 5, above.

b. **Should the IOUs include examples based on the equity and enhanced demand flexibility scenarios in their proposed applications?**

CalCCA has no response at this time.

6) **Should the IOUs include a proposed shared savings mechanism (SSM) for successfully implementing DER Orchestration as part of the proposed application?**

CalCCA supports the inclusion of a proposal for a Shared Savings Mechanism (SSM) but seeks clarification of the Commission's intent for the SSM. An SSM is defined as "an incentive

structure that allows utilities to share in the net cost savings generated by DER solutions"[32] but it is not clear with whom the net cost savings would be shared.

CalCCA understands the need for incentives to encourage any IOU functioning as the DSO to unlock as much distribution value from DERs as possible and forgo infrastructure investments in favor of DER flexibility. However, under a non-IOU DSO framework, an SSM may not be necessary. Any finding ordering proposed DER Orchestration applications should specify in detail how the SSM incentive would replace existing incentives. CalCCA does not support an additional incentive structure, but rather a realignment of existing structures to support the goals of successful DER orchestration.

7) Should the IOUs include a review of the DSO incentive structures from regulators of other jurisdictions such as the United Kingdom (Ofgem) and Australia for discussion in stakeholder workshops?

The Commission should review DSO structures operating in the UK and Australia, including marketplace, regulatory, and incentive structures. The review should also include an analysis of the rate-of-return framework, how it differs from California's, and a description of monitoring and oversight measures. CalCCA recommends that the Commission prepare a report with their findings in advance of a workshop, allowing time for review and facilitating discussion at the workshop.

8) Should the proposed applications address scaling and IOU readiness and the role of Advanced Distribution Management Systems/Distributed Energy Resources Management Systems (ADMS/DERMS)?

Any IOU applications to perform the DER Orchestration function of a DSO should address the scalability and readiness of their ADMS and DERMS platforms, and the role these systems will play in orchestrating DERs. The ADMS systems provide valuable real-time grid data and

[32] Ruling, footnote 3, at 8.

short-term forecasts that will inform demand flexibility needs and locations, regardless of the DSO framework. The IOUs are currently phasing in their enterprise DERMS, which exchange data with their ADMS and control IOU-owned DERs or the DERs of customers enrolled directly in their programs or tariffs. CalCCA is not aware of any plans or timelines for the IOUs to launch grid-edge DERMS, which would enable DERs managed by CCAs or third-party aggregators to provide flexibility services.

Achieving the objectives outlined in CalCCA's response to Section 3, Question 1 will require the orchestration of as many DERs as possible, regardless of who owns or manages the DERs and aggregations. The IOU enterprise DERMS currently being deployed focus only on IOU-owned or managed DERs, which represent a subset of the DERs operating in the state. Depending on the DSO framework, a combination of IOU enterprise and grid-edge DERMS may be required.

Alternatively, if an independent, non-IOU-led marketplace framework is adopted, IOU grid-edge DERMS may not be necessary. In this framework, IOUs would provide real-time grid data and short-term forecasts from their ADMS, and price or other data from their enterprise DERMS to the market operator. This framework would be an alternative to using a grid-edge DERMS to provide dispatch and pricing signals to each DER aggregator, reducing the burden on IOUs and aggregators by centralizing marketplace functions and encouraging greater participation by non-IOU-managed DERs. For these reasons, CalCCA again recommends that the Commission evaluate non-IOU-led DSO frameworks, including the independent marketplace framework, before requiring the IOUs to submit their applications.

9) How should the proposed applications demonstrate IOU readiness to implement DER orchestration? How should the Commission reconcile different states of readiness of each utility so that meaningful progress can be made?

The issue of IOU readiness is highly dependent on the DSO framework adopted. CalCCA recommends that the Commission first schedule workshops and provide stakeholders with

opportunities to comment on the DSO framework before addressing IOU readiness. There are certain criteria that can indicate general IOU readiness to support DER orchestration, such as the deployment of IOU ADMS systems and enterprise DERMS capabilities. However, until the Commission builds the record and issues a decision on a final DSO framework, CalCCA cannot fully respond to this question.

Addressing only the IOU-led DSO framework, the IOUs' readiness depends in part on the stage of deployment of both their enterprise and grid-edge DERMS. As discussed in CalCCA's response to Section 3, Question 8, CalCCA is not aware of any IOU plans or timelines for deploying grid-edge DERMS that would enable third-party- and CCA-managed DERs to provide flexibility services. Evaluating the IOUs' readiness under this framework would depend on their plans for deploying grid-edge DERMS and enabling CCA-managed DERs to participate.

10) Should the IOUs present their proposed strategy for achieving interoperability, including communications protocols, to enable scalable DER orchestration?

As CalCCA discussed in its responses to Section 3, Questions 8 and 9, any strategies for achieving interoperability depend heavily on the DSO framework. Under an independent marketplace operator framework, IOU interoperability is required with a single marketplace operator rather than with individual or third-party DER providers. However, if the Commission adopts an IOU-led DSO framework, it should require the IOUs to propose an interoperability strategy that maximizes DER participation. DER participation can, in part, be maximized by ensuring non-IOU (CCA and other) DER programs and customer resources will be incorporated into DER orchestration operations. The strategy should include communication protocols that reduce the cost and burden on customers, third-party aggregators, and CCAs managing DERs, thereby encouraging their participation.

11) Should the proposed DER Orchestration applications include a proposed phased implementation and deployment plan? If so, what elements should the plan contain?

CalCCA supports a phased implementation and deployment plan that starts with developing a roadmap and timelines, including milestones and deliverables, once guiding principles have been adopted and a DSO framework has been selected. The implementation and deployment plans should incorporate best practices gleaned from the deployment of DSOs and flexibility markets in the UK and Australia. The IOUs should begin developing and deploying pilots, leveraging third-party- and CCA-managed DERs integrated via grid-edge DERMS or a marketplace platform. CalCCA recommends that the IOUs create joint pilots with CCAs that have existing demand flexibility programs. CCAs already have customer data-sharing agreements in place, and several have deployed DERMS, which can be integrated with an IOU ADMS or grid-edge DERMS.

12) What potential cost-effective mechanisms or measures could be included as part of the proposed DER orchestration framework to demonstrate a net benefit to ratepayers?

See CalCCA's response to Question 3, above. While CalCCA does not recommend a specific cost-benefit methodology, it does recommend evaluating societal benefits in the context of DER orchestration. Additionally, any cost-benefit analysis should account for the customer's investment in DER to accurately reflect costs.

13) What potential benefit-cost methodology could these applications use?

See CalCCA's response to Section 3, Question 12 above.

14) How can IOU DSO-led DER Orchestration implementation be complementary and compatible with the potential rollout of real-time pricing?

CalCCA reiterates its position on the need to evaluate alternative DSO frameworks. Nevertheless, there are three key considerations that must be addressed to evaluate whether IOU

DSO-led DER orchestration may be complementary and compatible with, or even coexist with, the potential rollout of real-time pricing (RTP). *First*, to be compatible, DER orchestration must coordinate with LSEs on price-based signals and operational dispatch and scheduling. There are questions that need further consideration regarding this issue, including which entity would dispatch the resources that leverage RTP under an IOU DSO-led DER orchestration framework, and whether the DSO or the LSE would compensate participants.

Second, potential framework rules must prevent conflicting incentives and double compensation. An IOU DSO-managed market, with its active transactional postings and signals, may pose challenges or conflicts with the structure of RTPs, which are more passive mechanisms that motivate behavior. There is an inherent challenge between RTP and DER orchestration that must be addressed: RTP uses a pricing structure that participants may leverage to reduce energy costs, whereas a DER orchestration framework would provide compensation for services. Also, for customers participating in an IOU DSO-led DER orchestration framework via an RTP, there is the potential for double compensation[33], which must be further considered and prevented.

Third, the Commission must consider and address the compatibility of CCA and other LSE real-time rates. If an IOU DSO-led orchestration framework is complementary and compatible with RTP, the Commission must ensure that customers are not inadvertently or explicitly prevented from participating through IOU RTPs. The framework must also be flexible to accommodate future RTPs developed by LSEs over time.

[33] For example, double compensation could occur where a load reduction was incentivized by RTP where that rate is fully compensatory and does not require an additional payment if the same customer is participating within a DER. However, if the load reduction becomes a net export to the grid and the RTP does not pay the customer for export, then paying the customer as part of a DER would not be double compensation.

15) How should the proposed DER Orchestration applications address the role and participation of DER aggregators within the proposed framework on issues such as coordination with the DSO, performance standards, data exchange requirements, and metrics to address accountability mechanisms?

One of the main objectives of DER orchestration is to leverage as many DERs as possible to maximize ratepayer and grid benefits by optimizing existing capacity and deferring or avoiding capital investments. Any DSO framework should be agnostic to the entity that manages the DERs and should aim to maximize DER participation. CalCCA strongly supports a DSO framework that includes an independent market operator, which offers the greatest opportunity to achieve the objectives outlined in its response to Section 3, Question 1. Adopting an independent market operator framework can provide greater transparency, standardize data exchange and interoperability requirements, and reduce the burden on IOUs by creating a single interface to the market operator rather than multiple DER providers. Any performance standards, data exchange requirements, and accountability mechanisms should apply equally to all market participants, including DER aggregators, CCAs, and IOUs.

CalCCA also notes that CCAs are LSEs that serve roughly 15 million customers and are not private, for-profit aggregators. CCAs have existing customer data-sharing agreements in place with the IOUs, which provide metering and billing services on their behalf. The DER orchestration applications should recognize the unique role of CCAs, as well as the existing coordination efforts and relationships with the IOUs. CalCCA expects this coordination to continue and possibly strengthen, regardless of the DSO framework adopted.

16) Should the proposed DER Orchestration applications identify additional technology investments required to support DER orchestration implementation (e.g., DERMS enhancements, communications infrastructure, device-level controls)?

The technology investment requirements are highly dependent on the DSO framework, particularly regarding the IOUs' investments. An IOU-led DSO framework may require the

greatest investment in technology and communications infrastructure since the IOU would potentially be orchestrating DERs managed by multiple third-party aggregators and CCAs, requiring significant scaling of their DERMS platforms. The IOUs would likely need to procure and deploy grid-edge DERMS in addition to their enterprise DERMS.

The independent marketplace framework requires investment in the marketplace platform and integration/interoperability with the IOUs' ADMS, DERMS, and other systems. Non-IOU DER flexibility service providers would need to integrate with either the marketplace platform or an IOU grid-edge DERMS. The costs to the flexibility providers would depend on the communications protocol and communications gateway requirements. The costs to the IOUs and to flexibility service providers should be included in the DER orchestration applications, regardless of the framework adopted.

17) Should the proposed DER Orchestration applications request details on whether the above-mentioned technological capabilities should be customer-owned or utility-owned and what the estimated costs are?

The DER orchestration applications should include details on the ownership and estimated costs for the technological capabilities and requirements.

Ruling Section 4. Enabling DER Visibility to the CAISO and Coordination Between DSOs and CAISO

Section 4.2. TSO-DSO Coordination Workshop Scope and Objectives

What issues should be addressed in the TSO-DSO workshop related to DER visibility and coordination under a DER orchestration framework?

There are several issues regarding the visibility and coordination of DER orchestration between the DSO and the CAISO that are significantly affected by the DSO framework adopted. Operating a marketplace is a key function of a DSO, whether through an independent market operator or the IOUs' enterprise or grid-edge DERMS. Even under an IOU-led DSO, the IOUs could deploy a market platform instead of a grid-edge DERMS. Coordination and data exchange

between the CAISO and DSOs will vary depending on the DSO's framework and the systems used to orchestrate DERs.

Another important issue is ensuring treatment of resources and programs to enable DERs to participate in either or both the CAISO and DSO markets. The CAISO has existing market mechanisms to allow DER participation in wholesale markets and is developing a modified Proxy Demand Resource mechanism, with the goal of launching early next year.[34] Once the DSO framework has been selected, the Commission, the DSOs, the marketplace operator, and the CAISO should coordinate and plan to align existing and developing wholesale market mechanisms with the DSO market to ensure participants retain full flexibility to choose the market pathway(s) that best serves their unique portfolio needs. The CAISO and DSOs must also address issues such as DER registration, dual compensation, short-term forecasting, and potential congestion and power quality impacts of uncoordinated DER dispatches. Finally, the Commission should work with the CAISO to determine potential impacts on the development of real-time pricing structures and locational marginal pricing.

Should operational requirements and wholesale market participation be considered?

Yes, CalCCA recommends that operational requirements and wholesale market participation be considered for the DSO framework to ensure participants retain full flexibility to choose the market pathway(s) that best serves their unique portfolio needs.

Ruling Section 5. Cadence of Integrated Capacity Analysis Workshops

Should the ICA quarterly workshop requirement be reduced to biannual, aligning with the release of the biannual ICA reports?

[34] *See* CAISO Demand and Distributed Energy Market Integration Stakeholder Initiative, https://stakeholdercenter.caiso.com/StakeholderInitiatives/Demand-Distributed-Energy-Market-Integration.

CalCCA has no response at this time.

Should the IOUs be authorized to submit a joint Tier 2 advice letter to propose modifications to the frequency of the ICA workshops?

CalCCA has no response at this time.

Ruling Section 6. Grid Modernization Reports

1. **Should the Commission require the IOUs to submit their Biennial Grid Modernization Progress Reports in the fall of even-numbered years (e.g., 2026, 2028) to align with reporting requirements under Pub. Util. Code Section 913.6?**

CalCCA has no response at this time.

2. **Should the Commission adopt the proposed Appendix A as the standardized format and content requirements for IOU's biennial grid modernization update?**

CalCCA has no response at this time.

3. **What additional information, if any, should be included in the reporting requirements?**

The reporting requirements should be amended to require IOUs to include a description and status of integration with non-IOU-controlled systems, under both the Grid Management Systems and the Communications Infrastructure sections of the report. The proposed Appendix A reporting requirements cover the spectrum of grid modernization activities but do not recognize the need for non-IOU parties to monitor how IOU systems, tools, infrastructure, and applications will interact with their own systems, tools, infrastructure, and applications.

CalCCA recommends adding reporting on the development and scaling of grid modernization activities and how the implementation of the various items listed in Appendix A can interact with non-IOU-controlled DERs. Non-IOU LSEs are developing DERMS platforms concurrently as IOUs scale and develop their systems, and by adding this requirement, the legislature and other stakeholders will be able to better understand the status of increasing opportunities to fully leverage DERs across the state, as well as the remaining difficulties.

4. **What information, if any, should be omitted from the reporting requirements?**

CalCCA has no response at this time.

5. **Should the Commission establish a sunset or review date for Appendix A reporting requirements to ensure alignment with the evolving grid modernization technology and goals?**

CalCCA has no response at this time.

6. **Should the Commission require the utilities to use a Tier 1 or Tier 2 advice letter or other process to propose modifications to their grid modernization reporting approach or content?**

CalCCA has no response at this time.

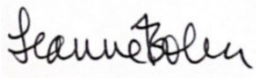
7. **Should the Commission authorize the Energy Division to direct changes to the content and format of the reporting approach?**

CalCCA has no response at this time.

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

April 20, 2026

April 27, 2026

Via Electronic Mail

California Public Utilities Commission – Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
(EDTariffUnit@cpuc.ca.gov)

Re: Protest of Joint CCAs to SCE Advice Letter 5784-E – Establishment of Technical Assistance Program Handbook Pursuant to Decision 25-12-005

Dear Energy Division Tariff Unit,

Pursuant to the California Public Utilities Commission's (Commission) General Order (GO) 96-B, Ava Community Energy (Ava), Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), Redwood Coast Energy Authority (RCEA), and San Jose Clean Energy (SJCE) (Joint CCAs) hereby protest Southern California Edison Company (SCE) Advice Letter (AL) 5784-E – Establishment of the Joint Investor-Owned Utilities Technical Assistance Program Handbook Pursuant to Decision (D.) 25-12-005, submitted on behalf of the joint investor-owned utilities (IOUs).[1] AL 5784-E was submitted by SCE on April 6, 2026.

AL 5784-E should not be approved as filed because the requested relief is unjust and unreasonable and does not reasonably implement Commission direction. The Joint CCAs support the establishment of the Technical Assistance (TA) Program and recognize its potential to improve customer experience, support interconnection, and facilitate adoption of electric vehicles among the customers served by the IOUs and the Joint CCAs. However, the TA Program Handbook (Handbook), as drafted, lacks sufficient implementation detail in key areas necessary to ensure effective and coordinated program delivery.

First, the Handbook does not adequately define how TA services will coordinate with the Community Choice Aggregators (CCAs) in the IOUs' respective service territories when advising shared customers. This omission is inconsistent with Commission direction, including direction that IOUs coordinate with CCAs on TA and relevant offerings, establish clear communication channels through the Handbook development process, and coordinate with

[1] Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Liberty Utilities (CalPeco Electric) LLC, Bear Valley Electric Service Inc., and PacifiCorp d/b/a Pacific Power.

CCAs at the customer level in developing load management plans.[2] The TA program is intended to support customers who are also enrolled in CCA service, but the Handbook does not acknowledge the categories of CCA offerings that may be relevant to TA program participants. These include incentives for electric vehicles (EVs) and EV charging equipment that reduce upfront costs, as well as rates and programs that reduce ongoing costs. These offerings are not limited to rates and may include programmatic offerings that influence both project design and long-term operations, such as demand response.[3] The Handbook also does not explain how those offerings will be incorporated into TA services across the program, including pre-energization support and load management planning. Nor does the Handbook describe how the required communication channels between IOU TA efforts and CCAs will function in practice.[4] Without this clarity, the TA program risks providing incomplete information to customers and does not ensure coordinated or comprehensive service delivery.

Second, the Handbook does not sufficiently define the scope of pre-energization support. This early-stage service is central to the TA Program's role in supporting customer projects. It helps ensure that projects are designed to meet customer charging needs while minimizing costs from the outset. However, the Handbook does not clarify whether the TA Program pre-energization support will include evaluation of project design approaches that reduce unnecessary infrastructure requirements and the associated costs and delays. This omission is significant because pre-energization planning is a primary driver of project cost and timing and is directly relevant to the Commission's directive in D.25-12-005 to align the TA Program with supporting timely customer energization.

Third, the Advice Letter identifies issues raised during the Commission-directed workshop and points to sections of the Handbook where those issues are addressed. The workshop record reflects that stakeholders raised questions on these topics and that the IOUs responded to those questions during the workshop. However, in several instances, the referenced sections do not substantively address the issues identified. This creates a mismatch between the IOUs' representations and the actual program design, limiting the Commission's ability to evaluate whether the Handbook reasonably reflects the issues raised during the workshop process.

Taken together, these deficiencies result in a TA Program design that lacks sufficient clarity and coordination to ensure that customers receive complete, actionable guidance as they pursue EV charging projects. As proposed, the Handbook does not clearly establish how the IOUs will coordinate with the CCAs to ensure the TA services will account for all relevant customer options for CCA customers, including CCA-specific programs that affect project design, load management, and ongoing operating costs, nor does it define the scope of pre-energization support in a way that ensures project designs are evaluated to avoid unnecessary infrastructure requirements. These gaps limit the program's ability to support cost-effective project development and to advance the Commission's objective of facilitating timely and efficient project energization.

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[2] D.22-11-040, *Decision Establishing Electric Vehicle Infrastructure Rules* (November 18, 2022), Conclusion of Law 105 at p. 224, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043682.PDF.
[3] *Id*. at p. 120.
[4] *Id*., Conclusion of Law 50 at p. 217.

Accordingly, the Joint CCAs respectfully request that the Commission conditionally approve AL 5784-E subject to modifications that:

(1) clarify the scope of CCA coordination within the TA services, including how relevant CCA offerings such as programs that affect customer load and operating costs, will be incorporated into customer guidance;
(2) define the scope of pre-energization support, including evaluation of project design approaches that minimize infrastructure requirements, cost, and timing; and
(3) ensure that the Handbook more accurately reflects the issues identified in the Workshop Record.

BACKGROUND

Advice Letter 5784-E was submitted by SCE on behalf of the joint IOUs pursuant to D.25-12-005. In that Decision, the Commission directed the IOUs to resume implementation of the TA Program and to develop a TA Program Handbook describing the scope and delivery of TA services. In addition, D.22-11-040 directs the IOUs to "coordinate with CCAs on TA and CCA-specific offerings for their customers (*e.g.,* DR programs.)"[5] The Commission also required the IOUs to conduct a public workshop to inform development of the Handbook prior to submission through a Tier 3 Advice Letter.

As described in D.25-12-005, the TA Program is intended to support customers pursuing transportation electrification (TE) projects by providing guidance on project development, interconnection, and energization. The Commission emphasized that the TA program should be structured to support customer projects and facilitate timely energization, making the scope and design of TA services central to achieving these objectives.

The IOUs held the workshop on February 3, 2026. Following that workshop, the IOUs submitted AL 5784-E, which includes the draft TA Program Handbook and the Workshop Report. The AL identifies issues raised during the workshop and points to sections of the draft Handbook where those issues are addressed.

As discussed below, while the Workshop Report reflects stakeholder questions and discussion, the Handbook does not substantively address several of those issues, particularly with respect to CCA coordination and the scope of pre-energization support.

JOINT CCA INTEREST

The Joint CCAs are the default Load Serving Entities (LSEs) for a substantial share of the customers within IOU service territories. In many of these territories, CCAs collectively service more electric load than the incumbent IOU.[6] CCAs currently serve more electric load in

[5] *Id*. at p. 120.
[6] CCA customers receive generation services from their respective CCA, and receive transmission, distribution, billing, and other such services from their IOU.

many of the IOUs' service territories than the IOUs do. As local public agencies, CCAs are also tasked with reducing GHG emissions associated with the electricity used by their customers. To that end, CCAs offer many programs aimed at achieving California's transportation electrification goals including, but not limited to, the following:

- EV charger incentive and technical assistance programs
  - MCE's EV Charging program, launched in 2018, provides rebates for EV charging stations at multifamily properties, businesses, and community-serving public locations. The program also offers bonus incentives for stations powered by 100% renewable energy service, and free technical assistance to help accelerate EV adoption.[7]
  - PCE's EV Ready program provides free technical support and rebates to help offset the costs of installing EV charging infrastructure at businesses and multifamily properties.[8]
  - PCE's GovEV public fleet electrification program provides free technical assistance, project planning, and funding to public agencies for new EVs and charging infrastructure for their fleets.[9]
  - RCEA manages the installation and operation of a 72-port public charging network, with 37 stations at 22 locations. All of RCEA's managed stations are Level 2 chargers. RCEA also provides technical assistance to customers seeking to install EV charging.
  - SJCE's Multifamily EV Charger Assistance Program, launched in 2024, provides incentives to multifamily properties to install Level 1 EV charging outlets, Level 2 EV charging outlets, and Level 2 EV charging ports[10]

- Managed EV charging programs
  - Ava SmartHome Charging, launched in March 2025, is an EV managed charging program that automatically shifts home charging to off-peak times and when renewable energy is cheaper and more available. Eligible Ava customers who charge their EVs at home can earn both one-time rewards and monthly rewards per vehicle.[11]
  - MCE Sync, launched in 2021, is an app-based managed EV charging and load shifting program that helps customers to reduce EV charging load during peak times, while also seeking to align EV charging load with high-solar daytime hours. The program provides eligible MCE customers with an enrollment bonus and monthly cash back for charging during low-carbon events.[12]
  - RCEA does not offer managed EV charging programs, but it does offer rates intended to incentivize electric vehicle charging. These rates mirror PG&E's EV-tailored rates and include the residential EV-A and EV2-A rates.

[7] https://mcecleanenergy.org/ev-charging/.
[8] https://www.peninsulacleanenergy.com/business/rebates-offers-business/ev-ready-program/.
[9] https://www.peninsulacleanenergy.com/public-organization/govev-program-public-fleet-electrification/.
[10] https://sanjosecleanenergy.org/ev-charger-assistance/.
[11] https://avaenergy.org/go-electric/electric-vehicles/smarthome-charging/.
[12] https://mcecleanenergy.org/mce-sync/.

- SJCE's Peak Rewards for Smart Homes program, launched in May 2025, offers a Managed Charging option to automatically shift participant home charging to off-peak times. Customers that successfully shift their charging receive $3/month in rewards. In 2026, SJCE will add the Midday Charging Bonus to encourage customers to plug in during peak solar generation hours. Participants that maximize charging during these hours will be able to earn up to $160/year in rewards.[13]

- EV rebate programs
  - PCE's Used EV Rebate Program offers savings toward the purchase of a used plug-in hybrid or fully-electric vehicle for income-qualifying eligible PCE residents. In combination with PCE's rebate, income-qualified residents may also qualify for additional incentives from regional and state programs.[14]
  - MCE's EV Instant Rebate Program lowers the cost of purchasing or leasing EVs for income-qualified MCE customers. Launched in May 2023, the program offers savings on the purchase or lease of an eligible EV at participating dealerships. This rebate may also be combined with other available incentives to further reduce the final vehicle costs.[15]
  - RCEA's EV Rebate program offers post-purchase incentives for new and used fully electric EVs to help reduce upfront costs of EV ownership. RCEA's EV Rebate can be stacked with other incentives.[16]
  - SJCE's EV Instant Rebate Program provides income-qualified customers with discounts when purchasing or leasing a new or used EV from participating car dealerships. EV Instant Rebates can be stacked with other available incentives to make EVs accessible for all.[17]

PROTEST

The Joint CCAs submit this protest to AL 5784-E on the grounds that the requested relief is unreasonable and does not reasonably implement Commission direction. As discussed below, while the IOUs have complied with the procedural requirements to submit a TA Program Handbook following a Commission-directed workshop, the resulting filing lacks sufficient clarity in key areas of program scope and coordination including coordination on CCA offerings that affect customer load and costs, and does not reasonably reflect the issues raised during that process. As a result, the proposed TA program is unreasonable and should not be approved without modification.

[13] https://sanjosecleanenergy.org/peak-rewards-for-smart-homes/.
[14] https://www.peninsulacleanenergy.com/residential/rebates-offers/ev-rebate-program/.
[15] https://mcecleanenergy.org/ev-rebate/.
[16] https://redwoodenergy.org/programs-rebates/rebates-incentives/ev-incentives/.
[17] https://sanjosecleanenergy.org/ev-rebates/.

(1) The Advice Letter Fails to Adequately Implement Commission Direction on CCA Coordination

D.22-11-040 directs the IOUs to coordinate with CCAs on TA and CCA-specific offerings for their customers, including programs such as demand response. The Commission also required the Program Handbook development process to establish clear and defined communication channels between IOU TA efforts and CCAs in their respective service territories.[18] It further directed the IOUs to coordinate with CCAs at the customer level in developing load management plans.[19]

The draft TA Program Handbook does not adequately implement this direction. Chapter 2.4 of the Handbook describes a recurring meeting cadence between the IOUs and CCAs to discuss CCA offerings and how the TA Program may complement those offerings. However, it does not explain how relevant CCA offerings will be consistently considered within TA service delivery. The Handbook does not demonstrate how these coordination activities will support customer-specific load management planning or incorporate relevant CCA offerings in that context. The Handbook does not reflect that current CCA offerings span incentives, rates, and a range of program types, consistent with Commission direction, that all are designed to limit customer costs. The Handbook also should establish a process to ensure that such offerings are considered, as appropriate, across relevant TA services described in Chapter 3. Without this clarity, it remains unclear how TA services will consistently incorporate CCA-specific information into customer guidance.

This omission is consequential because CCA offerings may materially influence both project design and customer costs. For example, CCA incentives for EV charging equipment may affect upfront infrastructure decisions, while managed charging programs may affect system design and long-term operating costs. Without a clear framework for incorporating these considerations, TA services may not reflect the full range of factors relevant to customer decision-making.

The lack of a defined integration framework is particularly evident across the core TA service components. The Handbook does not explain whether and how CCA coordination will be incorporated into pre-energization support, rate and load management guidance, or ongoing advisory services. Nor does it describe how information shared through the meetings described in Section 2.4 of the Handbook will be translated into consistent, actionable guidance for customers. This omission is inconsistent with Commission direction that coordination with CCAs extend to the development of customer-specific load management plans.

While the inclusion of a recurring meeting cadence suggests an intent to coordinate, the Handbook does not establish the structure needed to ensure that coordination results in meaningful integration of CCA-specific offerings into the TA services. The absence of defined processes linking coordination activities to TA service delivery limits the effectiveness of that coordination and does not demonstrate that the IOUs have established the clear and defined channels of communication contemplated by the Commission.

[18] D.22-11-040, Conclusion of Law 50 at p.217.
[19] *Id*., Conclusion of Law 105 at p. 224.

(2) The Advice Letter Fails to Define the Scope of Pre-Energization Support

Decision 25-12-005 directs the IOUs to structure the TA Program to support customer projects that facilitate timely energization. Pre-energization support is a central component of that objective, as early-stage project planning drives infrastructure requirements, project costs, and overall timelines.

The TA Program Handbook does not sufficiently define the scope of pre-energization support to ensure that these objectives are met. Chapter 3.1 describes pre-energization services in general terms. It does not clarify whether TA Advisors will consider project design approaches that could reduce infrastructure requirements and associated costs while still supporting the customer's actual EV charging needs. Instead, the Handbook refers generally to site planning and sizing without specifying how those recommendations will be developed or what considerations will be included.

This lack of specificity is material. Project design decisions during the pre-energization phase can determine whether a project will require the utility service upsizing, other service upgrades, or behind-the-meter (BTM) infrastructure investments that increase cost and delay energization. Without a defined expectation that TA services will consider approaches to meet customer needs while minimizing unnecessary infrastructure, the program may not consistently support cost-effective project development.

In addition, the Handbook does not establish how pre-energization recommendations will be evaluated or communicated to customers. In the Joint CCAs' experience assisting customers in designing EV charging projects, customers interested in installing EV charging will often assume that they should install more charging capacity than is necessary to meet actual usage needs. But the Handbook does not describe whether TA Advisors will present comparative design options, identify cost and timing implications, or otherwise support customers in selecting among feasible alternatives. The absence of this guidance limits the effectiveness of TA services in supporting informed customer decision-making and may result to unnecessary infrastructure investments that increase project costs and, in some cases, broader system costs. This gap is particularly relevant where load management strategies could reduce infrastructure needs but are not evaluated in coordination with available CCA programs.

Because pre-energization planning is a primary driver of both project cost and project energization timelines, the lack of a clearly defined scope for these services limits the TA Program's ability to achieve the Commission's objective of facilitating timely and efficient energization. As proposed, the Handbook does not provide sufficient detail to demonstrate that pre-energization support will be delivered in a manner consistent with that objective.

(3) The Advice Letter Does Not Reasonably Reflect the Issues Raised in the Workshop Report

Decision 25-12-005 required the IOUs to conduct a public workshop to inform development of the TA Program Handbook prior to submission via a Tier 3 Advice Letter. The

resulting Workshop Report documents stakeholder questions and discussion on key aspects of program design, including CCA coordination and the scope of pre-energization support.

AL 5784-E identifies these issues and points to sections of the draft Handbook where they are addressed. However, the Handbook does not substantively reflect several of the issues raised during the workshop. In particular, as discussed above, the draft Handbook does not define how the various services of the TA Program will incorporate CCA-specific offerings or how pre-energization support will consider project design approaches that influence infrastructure requirements, project costs, and project energization timelines.

This creates a disconnect between the issues identified in the Workshop Report and the program design described in the Handbook. While Table 1 of the Advice Letter indicates that these topics were addressed, the corresponding sections of the draft Handbook remain general and do not provide sufficient detail to demonstrate how the issues raised during the workshop have been incorporated into TA service delivery. As a result, these omissions limit the ability to evaluate whether the Handbook reflects the issues raised during the workshop process or whether the program design is sufficiently responsive to those issues.

CONCLUSION

For the foregoing reasons, the Joint CCAs respectfully request that the Commission conditionally approve AL 5784-E, subject to the following modifications to the Technical Assistance Program Handbook via a supplemental Tier 3 Advice Letter:

- Clarify the scope of coordination with CCAs, including how the IOUs will coordinate with CCAs within their respective service territories serving shared customers; acknowledgment that relevant CCA offerings vary in type, as reflected in Commission direction (e.g., demand response programs); and establish a process to ensure these are appropriately considered across the TA services described in Chapter 3.
- Define the scope of pre-energization support to ensure that TA services consider project design approaches that align infrastructure with actual charging needs and minimize unnecessary infrastructure requirements, costs, and project energization timelines, consistent with the Commission's direction to support timely and efficient customer energization, and support customers in evaluating available options.
- Revise the Handbook to more clearly reflect the issues raised during the workshop process, including providing sufficient detail to demonstrate how those issues are incorporated into TA service delivery.

The Joint CCAs thank the Commission for its consideration of this protest.

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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 IN RESPONSE TO THE ASSIGNED COMMISSIONER'S RULING ON TRACK 1 AND TRACK 2 DISTRIBUTED ENERGY RESOURCES ORCHESTRATION

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April 30, 2026

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends the Commission:

- Continue to build the record, as recommended by Opening Comments of multiple parties, to evaluate alternative DSO models to ensure a level playing field for non-IOU managed DER, including guardrails to prevent IOU conflicts of interest;

- Defer decisions on the IOUs' proposed interoperability requirements, which could result in unnecessary complexity and higher costs, as discussed in party Opening Comments;

- Reject SCE's and SDG&E's plans for a limited and temporary role of DER aggregators to reduce barriers and encourage CCA and DER aggregator participation; and

- In recognition of the significant number of DERs managed by non-wires LSEs, including CCAs, request that the CAISO: (1) include CCAs and other non-wires LSEs in the CAISO operational coordination discussions; and (2) consider non-IOU-led DER orchestration frameworks until a complete record is built and a decision is issued by the Commission on a DER orchestration framework.

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS IN RESPONSE TO THE ASSIGNED COMMISSIONER'S RULING ON TRACK 1 AND TRACK 2 DISTRIBUTED ENERGY RESOURCES ORCHESTRATION

California Community Choice Association[2] (CalCCA) submits these Reply Comments in response to party Opening Comments[3] responding to the *Assigned Commissioner's Ruling on Track 1 and Track 2 Distributed Energy Resources Orchestration* [4] (Ruling), dated March 23, 2026, and the *Email Ruling Granting Request for Extension on Comments and Workshop*, dated April 3, 2026.[5]

I. INTRODUCTION

Party Opening Comments demonstrate varying party positions on the proposed investor-owned utility (IOU) –led distributed energy resources (DER) orchestration framework. In fact,

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

[3] All references herein to party Opening Comments are to the Opening Comments filed in this proceeding, Rulemaking (R.) 21-06-017, on or about April 20, 2026.

[4] *Assigned Commissioner's Ruling on Track 1 and Track 2 Distributed Energy Resources Orchestration*, R.21-06-017 (Mar. 23, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K997/602997407.PDF.

[5] *Email Ruling Granting Request for Extension on Comments and Workshop*, R.21-06-017 (Apr. 3, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M603/K941/603941311.PDF.

many parties, including CalCCA, advocate for continued exploration of alternative distribution system operator (DSO) models. The direction taken for the DER orchestration framework has significant implications not only for costs but also for the effective optimization of customer-owned DER to support efficient and reliable grid operations. These decisions on how to optimize customer-owned DER are also being considered amid significant growth in building and transportation electrification. The California Public Utilities Commission (Commission) must build a record on which to base the selection of a DER orchestration framework before proceeding in order to fully understand the implications of each framework. This extends to the determination of interoperability requirements, the role of DER aggregators, and coordination between the DSOs and the California Independent System Operator (CAISO).

CalCCA supports multiple party Opening Comments recommending that the record be further developed to: (1) evaluate alternative DSO models; (2) create a level playing field for non-IOU managed DER; and (3) adopt guardrails to address IOU conflicts of interest. CalCCA opposes the adoption of the IOUs' proposed interoperability requirements, and the limited view of the role of DER aggregators as described in Opening Comments from Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E). Lastly, CalCCA supports modifying the operational framework described in the CAISO's Opening Comments to consider non-IOU-led DER orchestration and to include community choice aggregators (CCAs).

As set forth below, CalCCA recommends the Commission:

- Continue to build the record, as recommended by Opening Comments of multiple parties, to evaluate alternative DSO models to ensure a level playing field for non-IOU managed DER, including guardrails to prevent IOU conflicts of interest;
- Defer decisions on the IOUs' proposed interoperability requirements, which could result in unnecessary complexity and higher costs, as discussed in party Opening Comments;

- Reject SCE's and SDG&E's plans for a limited and temporary role of DER aggregators to reduce barriers and encourage CCA and DER aggregator participation; and

- In recognition of the significant number of DERs managed by non-wires load-serving entities (LSE), including CCAs, request that the CAISO: (1) include CCAs and other non-wires LSEs in the CAISO operational coordination discussions; and (2) consider non-IOU-led DER orchestration frameworks until a complete record is built and a decision is issued by the Commission on a DER orchestration framework.

II. THE COMMISSION SHOULD ADOPT PARTY RECOMMENDATIONS TO BUILD THE RECORD TO EVALUATE ALTERNATIVE DSO MODELS BEFORE ENDORSING AN IOU-LED DSO

The Commission should continue building the record to evaluate alternative DSO models, including through additional workshops and comment opportunities, before endorsing an IOU-led DSO, in response to concerns raised in party Opening Comments. As set forth below, CalCCA concurs with the comments of The Public Advocates Office at the California Public Utilities Commission (Cal Advocates), Advanced Energy United (AEU), and the Clean Coalition, disagreeing with the Ruling's finding that a sufficient record has been developed to support an IOU-led DER orchestration framework.[6] In addition, the Commission should adopt recommendations of Nexamp, Inc. (Nexamp), California Solar and Storage Association (CalSSA), and Utility Consumers' Action Network (UCAN) to create an open and competitive market in which DER providers are fairly compensated for their services, rather than an IOU-centric framework.[7] Finally, CalCCA agrees with the Environmental Defense Fund (EDF) and the California Efficiency + Demand Management Council (CEDMC) that conflicts of interest arising from IOU-led DER orchestration must be addressed before proceeding with any DSO framework.[8]

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6 *See* Cal Advocates Opening Comments; AEU Opening Comments; and Clean Coalition Opening Comments.

7 *See* Nexamp Opening Comments; CalSSA Opening Comments; and UCAN Opening Comments.

8 *See* EDF Opening Comments; and CEDMC Opening Comments.

First, while not expressly endorsing the exploration of alternative DER orchestration frameworks, Cal Advocates nevertheless takes issue with the rapid pace of the proposed process and the lack of opportunities to vet the framework and the application process.[9] Cal Advocates states that "the proposed process moves to IOU applications too quickly and before fully developing Commission guidance on a DER orchestration framework," and suggested that additional workshops and further development of the framework requirements are needed.[10]

AEU and the Clean Coalition both echo CalCCA's arguments that the Commission must continue building the record to evaluate alternative DSO models before assigning the DER orchestration role to the IOUs. AEU states:

> The record that the Commissioner relies on in the Ruling is the Track 2 Future Grid Study and parties' comments, which were submitted more than fifteen months ago. Neither the FGS Report nor parties' comments support the Ruling's proposal to create new, separate IOU Applications for DER Orchestrion Frameworks.[11]

Similarly, Clean Coalition states that it is "concerned that the record in this track is not yet sufficiently developed," and that the "issues are highly consequential and require greater detail and granularity than the current record appears to provide."[12]

Second, other parties stress the need to create a level playing field for non-IOU managed DERs to participate in the DER orchestration framework. Nexamp argues that the "Commission should avoid assuming that IOU-led orchestration is the default model and should consider a framework that enables independent third parties and aggregators to provide orchestration services on a comparable basis."[13] CalSSA states that "it is essential for the Commission to make

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9 Cal Advocates Opening Comments, at 3.
10 *Ibid.*
11 AEU Opening Comments, at 3-4.
12 Clean Coalition Opening Comments, at 1.
13 Nexamp Opening Comments, at 3.

clear that stakeholders will be given the opportunity to put forward proposals to be considered alongside utility proposals."[14] UCAN also expresses caution before continuing down the path towards an IOU-led orchestration framework, stating:

> The framework should explicitly promote a competitive ecosystem where third-party aggregators and CCAs can offer orchestration services. An overly centralized, IOU-exclusive model restricts innovation and typically results in higher software and administrative costs being passed on to ratepayers.[15]

Third, several parties mirror CalCCA's concerns about IOU conflicts of interest in the context of an IOU-led DER orchestration framework. In justifying the need for establishing a shared savings mechanism, EDF states that the IOUs "are profiting from investments in the core underlying grid modernization investments."[16] CEDMC states that "[g]uardrails are needed to prevent utility self-preferencing, crowd-out of third-party solutions, or expansion of utility control beyond what is operationally necessary."[17]

There is clearly significant concern about the insufficient record to develop an IOU-led DER orchestration framework, and a strong desire to continue evaluating unresolved issues and exploring other frameworks that may provide greater transparency, a level playing field, and greater savings. The Commission should therefore continue to build the record to evaluate alternative DSO models through additional workshops and comment opportunities before making any decision on a DER orchestration framework.

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14 CalSSA Opening Comments, at 2.
15 UCAN Opening Comments, at 3.
16 EDF Opening Comments, at 9.
17 CEDMC Opening Comments, at 5.

III. THE COMMISSION SHOULD DEFER DECISIONS ON THE IOUS' PROPOSED INTEROPERABILITY REQUIREMENTS, WHICH COULD CREATE UNNECESSARY COMPLEXITY AND HIGHER COSTS

The Commission should defer any decisions on the IOUs' proposed interoperability requirements until after a thorough evaluation and determination of an appropriate DSO framework. Opening Comments demonstrate a wide divergence on interoperability requirements between the IOUs and other parties. The IOUs' comments mostly reference ongoing discussions about communications protocols in a separate track of this proceeding, while non-IOU party comments emphasize the cost and complexity of centralized IOU platforms. As CalCCA states in its Opening Comments, the strategies for achieving interoperability depend on the DSO framework the Commission adopts.[18] The Commission must therefore carefully evaluate the costs under different DSO frameworks, along with the potential impact on DER participation, before establishing interoperability requirements.

SCE, SDG&E, and Pacific Gas and Electric Company (PG&E) provide only brief responses to Question 10 on achieving interoperability. PG&E merely proposes using standardized protocols, such as the Institute of Electrical and Electronics Engineers (IEEE) 2030.5 protocol.[19] SCE similarly states that it "has made clear on the Track 3 record that it believes 2030.5 is the key to scaling DER orchestration."[20] SDG&E suggests that interoperability may have limited value, stating that "[w]ithout state action for interoperability, SDG&E's ability to signal devices will be limited, or more expensive, given the need to pay signal licensing fees."[21]

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18 CalCCA Opening Comments, at 19.
19 PG&E Opening Comments, at 11.
20 SCE Opening Comments, at 7.
21 SDG&E Opening Comments, at 16.

Several other non-IOU parties presented different views on interoperability requirements in their Opening Comments, which demonstrate the need to ensure cost-effective interoperability, allowing widespread DER participation from different technology providers:

- EnergyHub: "Over-emphasizing complex, expensive interoperability standards can delay implementation and increase costs without providing immediate grid value."[22]

- 350 Bay Area: "Key factors in achieving the primary objective include avoiding excessively costly approaches to orchestration through Advanced Distribution Management Systems/Distributed Energy Resources Management Systems (ADMS/DERMS) or proprietary or costly communication requirements."[23]

- UCAN: "Currently, the IOUs frequently position their centralized Advanced Distribution Management Systems (ADMS) and Distributed Energy Resources Management Systems (DERMS) as the sole mechanisms capable of orchestrating load, often pushing for exclusive reliance on the IEEE 2030.5 protocol down to the individual device level. However, requiring all DERs to integrate directly into a centralized utility DERMS creates an unnecessary IT bottleneck and drives up compliance costs. Third-party aggregators effectively operate as Virtual Power Plants (VPPs) and already possess sophisticated cloud-based software capable of managing thousands of end-use devices using protocols like OpenADR."[24]

- EDF: Stated that "… interoperability is a key component of scaling DER orchestration. Any communications protocols used must allow for widespread participation by a diverse array of DERs from a wide range of technology providers."[25]

- Universal Devices: Stated that the Track 3 record in this proceeding "demonstrates that restricting DSO-to-BTM communications to IEEE 2030.5 cloud service providers would exclude the majority of deployed residential BTM devices and the aggregators that currently serve them via OpenADR."[26]

CalCCA agrees with the non-IOU parties that an IOU-led DER orchestration framework that relies on establishing communication with complex IOU ADMS/DERMS platforms or dictates specific communication protocols will be costly and limit DER participation. This is

22 EnergyHub Opening Comments, at 3.
23 350 Bay Area Opening Comments, at 2.
24 UCAN Opening Comments, at 4-5.
25 EDF Opening Comments, at 11.
26 Universal Devices Opening Comments, at 3.

counter to the aim of unlocking economic opportunities for DERs to provide grid support and to the goal of meeting state climate policy goals. The Commission should therefore defer decisions on the IOUs' proposed interoperability requirements, which would limit participation and potentially drive up the costs of DER orchestration.

IV. SCE'S AND SDG&E'S PLANS FOR A LIMITED AND TEMPORARY ROLE FOR DER AGGREGATORS SHOULD BE REJECTED TO REDUCE BARRIERS AND ENCOURAGE CCA AND DER AGGREGATOR PARTICIPATION

The Commission should reject SCE's and SDG&E's limited view of the role that DER aggregators will play in supporting the objectives of DER orchestration and instead find ways to reduce barriers and encourage CCA and DER aggregator participation. While SCE and SDG&E acknowledge that aggregators will play a role, they downplay the significant role that DER aggregators, including CCAs, can play in supporting efficient and reliable grid operations.

For its part, SCE states:

> ***At the outset***, especially if deployment of orchestration is expected ***in the short-term***, it is likely that third-party aggregators will be necessary at the grid edge (i.e., to aggregate customer DERs) due to the difficulties in interfacing with customer DER APIs (e.g., customers not wanting the utility to have access, lacking the technical capability and contractual ability to access EV telematics, etc.). Ultimately, SCE plans to deploy additional capabilities via its Demand Flexibility Management System (DFMS).[27]

This statement implies that SCE views aggregators as a temporary solution until it develops the ability to control customer-owned DERs directly. While SCE provides no further explanation of the capabilities it intends to deploy through its DFMS, it appears to intend for DFMS to be the long-term solution, leaving the role of CCAs and third-party aggregators uncertain.

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[27] SCE Opening Comments, at 10 (emphasis added).

SDG&E, on the other hand, makes it clear that aggregators must be under contract with the utility or participate in an IOU tariff for each distribution service they intend to provide. SDG&E further expresses a pessimistic view of the value of such services, stating:

> At present, opportunities for DERs to provide distribution services appear quite limited at the compensation levels that would be necessary for DER owners to allow the utility to control DER operation, and that would provide overall ratepayer benefit.[28]

SDG&E cites its experience with the discontinued Distribution Infrastructure Deferral Framework (DIDF) as a reason for its skepticism of the value DER aggregators may be able to provide for avoiding capital investments in the distribution grid.[29] The DIDF required DER providers to respond to solicitations for short-term contracts for the limited number of deferral opportunities IOUs identified during the annual distribution planning process. A major reason for DIDF's failure was the lengthy process for short-term deferral contracts, which required a significant investment of time and resources from DER providers without the certainty of long-term revenue to recover those costs. Yet in its response to the question of the role of aggregators, SDG&E states that "aggregators will be committed via utility contract and/or tariff to ensure that the aggregator's DER-owning counterparties respond to the DSO's dispatch instructions," rather than participating via an open and transparent market-based framework.[30]

The Ruling identifies the following scoped issue for Track 2 of this proceeding:

> What are the operational needs necessary to efficiently operate a high DER grid and unlock economic opportunities for DERs to provide grid services, limit market power, reduce ratepayer costs, increase equity, support grid resiliency, and meet State policy objectives?[31]

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28 SDG&E Opening Comments, at 4-5.
29 *Id*., at 5.
30 *Id*., at 17.
31 Ruling, at 2.

The Ruling also included a summary of the objectives for this Rulemaking, including to "plan and operate a distribution system that can support a large number of distributed energy resources on the grid in the future."[32] This objective cannot be met with the extremely limited role SCE and SDG&E propose for DER aggregators. Given the large number of DERs enrolled in CCA and other LSE programs or through third-party aggregators, the IOUs' objective should be to maximize opportunities for CCAs and DER aggregators to provide efficient grid services. The Commission should therefore reject SCE's and SDG&E's limited views of the role of DER aggregators and instead require them to find ways to reduce barriers and encourage their participation.

V. THE COMMISSION SHOULD REQUEST THAT THE CAISO INCLUDE CCAS AND OTHER NON-WIRES OPERATOR LSES IN THE OPERATIONAL COORDINATION DISCUSSIONS AND CONSIDER NON-IOU-LED DER ORCHESTRATION FRAMEWORKS

The Commission should request that the CAISO consider non-IOU-led DER orchestration models in the operational coordination discussions the CAISO is currently undertaking with the IOUs and other non-jurisdictional entities to improve coordination at the transmission and distribution (T&D) interface. Coordination procedures and mechanisms cannot be fully evaluated until the Commission builds a complete record and issues a decision on a DER orchestration framework. Further, the Commission should recommend that future discussions on operational coordination include CCAs among the non-wires operator LSEs, given the significant number of DERs they manage.

The CAISO's Opening Comments describe a set of processes and data exchanges to support DER visibility at the T&D interface, improve forecasting, address DER uncertainty, and enable enhanced operational coordination, ensuring reliable and efficient grid operations.[33] The

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32 *Ibid*.

33 *See* CAISO Opening Comments.

Ruling highlights the significance of this effort, stating that "DER visibility is important to help the CAISO understand how each type of DER can impact CAISO load."[34] The Ruling includes among the goals of DSO-CAISO coordination "clarifying roles, responsibilities, and data-sharing protocols so that DERMS development aligns with CAISO's operational needs."[35] Certain issues, including DER data, communications protocols, DER behavior, and short-term DER forecasting, are highly dependent on the DSO framework. Basic grid operational functions will remain with the IOUs regardless of the DSO framework, but under an independent marketplace framework, many functions related to DER operation and coordination will shift to the marketplace operator.

The CAISO states that the first phase of the operational coordination effort is "focused on assessing existing coordination practices and identifying gaps between current and desired future states," and that this work is expected to conclude in May 2026.[36] The next phase will focus on "establishing high-level processes to improve DER information and visibility," and "beginning the design of data exchange mechanisms to support enhanced operational coordination."[37] It is important that the next phase of development of CAISO's operational coordination effort also consider non-IOU-led DER orchestration to ensure these processes and mechanisms can support alternative DSO frameworks.

While CCAs do not own or operate grid infrastructure, they represent roughly one-third of the CAISO's load and manage significant numbers of DERs, including through DERMS and virtual power plant programs. Since some CCA DER programs may involve participation in

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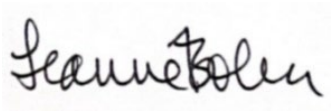
34 Ruling, at 10.
35 *Ibid.*
36 CAISO Opening Comments, at 5.
37 *Ibid*.

CAISO markets, it is important that they are included in these discussions to ensure efficient use of grid resources.

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,



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CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulations.	R.25-08-004

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

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April 30, 2026

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends that the Commission:

- Immediately increase the exemption threshold for Screen Q from one megavolt-ampere (MVA) to five MVA to reduce the backlog of projects subject to transmission independence testing; and
- Adopt a framework for penalties associated with an IOU's failure to comply with interconnection timelines, with the following elements:
    - Tiered fines applied quarterly to each of the timelines the IOUs are required to track;
    - Periodic reviews of the fines to ensure the levels provide adequate motivation to the IOUs for improvement; and
    - Additional daily fines for persistent IOU non-compliance with timelines.

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S OPENING COMMENTS ON ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

California Community Choice Association[2] (CalCCA) submits these opening comments pursuant to the *Assigned Commissioner's Scoping Memo and Ruling*[3] (Ruling), dated March 3, 2026, and to the *Email Ruling Granting Extension for Comments, Motion to Late File NOI, and Motions for Party Status*,[4] dated March 6, 2026.

I. INTRODUCTION

Community choice aggregators (CCA) are increasingly leveraging customer-owned distributed energy resources (DER) to reduce resource adequacy costs, increase customer affordability, improve reliability and resiliency, and achieve greenhouse gas reduction goals for the communities they serve. To help achieve these goals, several CCAs have active virtual power

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

[3] *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking (R.) 25-08-004 (Mar. 3, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M601/K158/601158095.PDF.

[4] *Email Ruling Granting Extension for Comments, Motion to Late File NOI, and Motions for Party Status*, R.25-08-004 (Mar. 6, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K998/602998550.PDF.

plant (VPP) programs and manage customer-owned DERs using DER Management Systems.[5] Given these activities, CCAs have a strong interest in the California Public Utilities Commission's (Commission) efforts to improve Electric Tariff Rule 21 (Rule 21) of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, the IOUs), governing interconnecting DERs to the IOUs' distribution systems.

The Ruling determines that the following issues should be considered in Phase 1 of this proceeding: (1) whether Screens Q and R should be modified; (2) whether interconnection timeline rules and compliance requirements established for the IOUs in Decision (D.) 20-09-035 should be modified; and (3) whether the interconnection fee for non-net billing tariff and non-net energy metering resources should be revised. CalCCA's comments herein respond to questions in Appendix A to the Ruling (Appendix A) regarding Screen Q, and non-compliance with interconnection timeline rules.

As set forth below, CalCCA recommends the Commission:

- Immediately increase the exemption threshold for Screen Q from one megavolt-ampere (MVA) to five MVA to reduce the backlog of projects subject to transmission independence testing; and
- Adopt a framework for penalties associated with an IOU's failure to comply with interconnection timelines, with the following elements:

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[5] *See, e.g.*, *Peninsula Clean Energy, Silicon Valley Clean Energy Jointly Launch Demand Flexibility Initiatives* (Nov. 3, 2025), https://svcleanenergy.org/news/peninsula-clean-energy-silicon-valley-clean-energy-jointly-launch-demand-flexibility-initiatives/; *MCE Unveils Plans for Virtual Power Plant to Benefit Disadvantaged Richmond Residents and Business* (June 21, 2022), https://mceecleanenergy.org/mce-unveils-plans-for-virtual-power-plant-to-benefit-disadvantaged-richmond-residents-and-businesses/; *Ava Community Energy Announces Ambitious Virtual Power Plant Initiative to Help its 2M Customers Optimize Their Energy Investments While Relieving Stress on the Grid* (Apr. 24, 2025), https://avaenergy.org/news/ava-announces-virtual-power-plant-initiative/; *New CPA Solar and Battery Access Program Can Reduce Electric Bills of Eligible Customers by Up to 70%* (May 19, 2025), https://cleanpoweralliance.org/2025/05/19/new-cpa-solar-and-battery-access-program/.

- Tiered fines applied quarterly to each of the timelines the IOUs are required to track;
- Periodic reviews of the fines to ensure the levels provide adequate motivation to the IOUs for improvement; and
- Additional daily fines for persistent IOU non-compliance with timelines.

II. CALCCA RESPONSES TO APPENDIX A OF THE RULING

The following provides CalCCA's responses to Appendix A, Questions 1(i), 1(vii), and 1(viii) in Section A, and to Question 1(vii) in Section B. CalCCA has no responses to Questions 1(ii-vi), 1(ix-xiii), and 2(i-vi) in Section A, 1(i-vi) in Section B, or 1, 2, and 3(i-ii) in Section C, but reserves the ability to comment at a later time.

A. Modifications to Screens Q and R.

1. Should the Commission modify Screens Q and R? Include in your response answers to the following questions:

i. What aspects of Screen Q and/or Screen R require modification? Why?

CalCCA supports increasing the threshold for projects exempt from Screen Q from one MVA to five MVA as an immediate means of reducing the significant backlog of projects that have failed Screen Q. Under the current Rule 21 practice, projects that fail Screen Q are required to apply for interconnection under the California Independent System Operator's (CAISO) Wholesale Distribution Access Tariff (WDAT), which can take several years to complete. The Coalition for Community Solar Access (CCSA) offered the following observation of the current WDAT process in its Order Instituting Rulemaking (OIR) Opening Comments:[6]

[6] All references herein to party Opening Comments are to the OIR Opening Comments filed in this proceeding, R.25-08-004, on or about October 20, 2025.

> If a DER facility fails Screen Q it is required to withdraw its Rule 21 application, apply for interconnection under WDAT and enter the CAISO cluster study process. This causes significant delay because the recent trend of CAISO "superclusters" means that project interconnection can take multiple years to complete. The clusters are overflowing with utility-scale projects (many of which will drop out), which results in lengthy study periods. Any DER project that cannot proceed under Rule 21 today is realistically looking at not being able to complete the interconnection process through WDAT for 3 years or more, which means many otherwise viable projects end up being abandoned.[7]

The California Energy Storage Alliance (CESA) further explained that:

> DERs up to 5 MW are generally distribution-level resources that do not create bulk transmission system reliability issues in isolation. Subjecting them to Screen Q introduces disproportionate costs and delays relative to their actual impact.[8]

Increasing the exemption threshold for projects subject to the Screen Q review from one MVA to five MVA will reduce the backlog in the CAISO cluster study process, benefiting both smaller projects that minimally impact the transmission system along with utility-scale projects that do impact the transmission system. While changing the threshold will not resolve all issues with Screen Q, this modification can be accomplished quickly and should be taken as a first step to other reforms. The Commission should therefore adopt this near-term change as quickly as possible, as it continues to explore longer-term modifications to Screen Q.

vii. What changes, if any, do you propose the Commission adopt? Why?

See CalCCA's response to Question 1(i) in Section II.A, above.

viii. Did any party/parties support your proposals in their comments on the instant OIR?

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7 CCSA Opening Comments, at 4.

8 CESA Opening Comments, at 6.

Several parties expressed support in their Opening Comments for increasing the exemption threshold for Screen Q from one MVA to five MVA, including CCSA, CESA, the Solar Energy Industries Association (SEIA), Advanced Energy United (AEU), and the California Solar and Storage Association (CalSSA).[9] While CalCCA did not advance this proposal in its Opening Comments, it expressed support in Reply Comments for the change in the exemption threshold for Screen Q.[10]

B. Interconnection Timelines Established for IOUs

1. Should the Commission take measures to modify the interconnection rules and requirements established for IOUs' in D.20-09-035? If so, what measures do you recommend? Include in your response answers to the following questions:

vii. Should the Commission adopt any of the proposals presented by parties for timeline compliance mechanisms? If so, provide a detailed description of how the proposal should be implemented. What are the drawbacks and merits of the proposals provided?

The Commission should adopt the penalty framework proposed by CalSSA in its August 28, 2025, Complaint against PG&E and SCE (CalSSA Complaint).[11] The Complaint alleges that CalSSA's member companies "have suffered damages due to the gross and repeated violation of interconnection timelines in Rule 21,"[12] and proposes the following tiered quarterly penalty framework:

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[9] *See* CCSA Opening Comments, at 3-6; CESA Opening Comments, at 6-8; SEIA Opening Comments, at 2; AEU Opening Comments, at 4; and CalSSA Opening Comments, at 26.

[10] *See CalCCA's Reply Comments on the Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulations* (CalCCA Reply Comments), R.25-08-004 (Nov. 10, 2025), at 3-4, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M586/K376/586376831.PDF.

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

[12] CalSSA Complaint, Appendix at 1.

CalSSA Complaint, Table 7: Proposed Quarterly Penalty for Each Timeline[13]

Compliance Rate	*Fine in dollars*
95% - 100%	$0
85% - 95%	$125k
75% - 85%	$250k
65% - 75%	$375k
55% - 65%	$500k
45% - 55%	$625k
35% - 45%	$750k
25% - 35%	$875k
15% - 25%	$1 million
0% - 15%	$1.125 million

CalSSA's tiered framework proposes increasing penalties based on the IOU's interconnection timeline performance. The framework is intended to motivate the IOUs to achieve and maintain high rates of compliance with interconnection timeline requirements established in D.20-09-030.[14] Importantly, CalSSA's proposed penalty framework applies to each of the interconnection timelines set forth in the Decision that the IOUs are required to track, ensuring the IOUs implement procedural improvements for each step of the interconnection process. The Commission should also adopt SEIA's proposal to have penalties be shareholder-funded, to further motivate compliance with the timelines.[15]

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[13] CalSSA Complaint, Appendix, Table 7, at 32-33.

[14] D.20-09-030, *Decision Adopting Recommendations from Working Groups Two, Three, and Subgroup* (Decision), R.17-07-007 (Sept. 24, 2020), Ordering Paragraph 22 requires the IOUs to track 19 listed timelines for reporting purposes, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M347/K953/347953769.PDF.

[15] SEIA Opening Comments, at 13.

The Commission should periodically review and, if necessary, revise the proposed fines to ensure continued improvement in compliance with each tracked timeline. If the Commission determines that the IOUs are not making satisfactory progress to improve overall timeline compliance, it should consider increasing the fines until compliance is achieved. If an IOU continually fails to improve its timeline compliance, the Commission should also consider imposing daily fines for individual projects, as proposed by the Interstate Renewable Energy Council (IREC) and Green Power Institute (GPI).[16]

The Commission should implement this penalty structure as soon as possible, given the impending expiration of the federal Investment Tax Credit (ITC) for clean energy projects, as noted in Opening Comments of IREC, CalSSA, PearlX, and SEIA.[17] Continued delays in interconnecting projects put developers at substantial financial risk if ITC milestones are not met. Additionally, California has prioritized the development of clean energy as a key component of achieving carbon neutrality by 2045. Governor Gavin Newsom's Executive Order N-33-25 (Executive Order) directs state agencies to take "all steps necessary and authorized by law to accelerate and prioritize all permitting, approval, and other agency actions that would enable and expedite the development of such projects."[18]

While the proposed penalty framework will create additional administrative oversight, the associated costs are small relative to the costs to developers of missed federal tax incentives and project delays, and to the state in terms of meeting its ambitious climate goals. In D.20-09-030, the Commission declined to adopt financial penalties, finding that they were premature at

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16 IREC Opening Comments, at 6; GPI Opening Comments, at 8.

17 *See* IREC Opening Comments, at 5; CalSSA Opening Comments, at 27; PearlX Opening Comments at 1-3; and SEIA Opening Comments at 10-11.

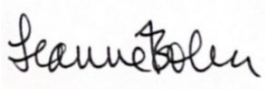
18 Governor of California, Gavin Newsom, Executive Order N-33-25 (Aug. 29, 2025), at 3, https://www.gov.ca.gov/wp-content/uploads/2025/08/Clean-Energy-EO_8.29.25_FINAL.SIGNED.pdf.

that time, adding that it "must first determine whether timeline certainty is improving."[19] More than five and a half years since the issuance of the Decision, PG&E and SCE have still not consistently met the timelines the Commission established. CalCCA therefore recommends that the Commission take immediate and strong action to implement the proposed penalty framework, consistent with the Executive Order and in light of the IOUs' failure to meet interconnection timelines established in the Decision.

III. 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

April 30, 2026

[19] Decision, at 97.