MARCH FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 24-01-017 (Issued February 1, 2024)

OPENING COMMENTS OF THE JOINT BIOMAT COMMUNITY CHOICE AGGREGATORS ON THE ORDER INSTITUTING RULEMAKING

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March 1, 2024

Attorney for the
Joint BioMAT Community Choice Aggregators

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	))))))	Rulemaking 24-01-017 (Issued February 1, 2024)

OPENING COMMENTS OF THE JOINT BIOMAT COMMUNITY CHOICE AGGREGATORS ON THE ORDER INSTITUTING RULEMAKING

Pursuant to Rule 6.2 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and in accordance with Ordering Paragraph ("OP") 6 of the *Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program*, issued on February 1, 2024 ("RPS OIR"), Central Coast Community Energy, Marin Clean Energy, Orange County Power Authority, Pioneer Community Energy, Redwood Coast Energy Authority, and Valley Clean Energy (collectively, the "Joint BioMAT CCAs") hereby file these opening comments for the principal purpose of requesting that the end date for the Bioenergy Market Adjusting Tariff ("BioMAT") program be included as a distinct issue to be addressed in this proceeding.[1] The Joint BioMAT CCAs also request that the Commission's Energy Division initiate another review of the BioMAT program for the purpose of assessing and recommending programmatic changes in light of performance to date and recent participation by Community

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[1] As it stands now, the RPS OIR includes the following issue in the Preliminary Scoping Memo: "Ongoing monitoring, reviewing ***and revising***, as needed, all RPS procurement methods and tariffs, such as…the Bioenergy Market Adjusting Tariff (BioMAT)." (RPS OIR at 7; ***emphasis*** added.) As further described below, the Joint BioMAT CCAs request that the final Scoping Memo expressly include as a distinct issue the consideration of whether to extend the BioMAT program end date, which is currently set to expire on December 31, 2025.

Choice Aggregators ("CCAs") in the BioMAT program.

The Joint BioMAT CCAs are listed as respondents in this proceeding and look forward to participating in this proceeding.[2]

I. INTRODUCTION

Participation by CCAs in the BioMAT program is a relatively recent occurrence. Following the Commission's rejection of a staff proposal in 2020 that, if approved by the Commission, would have allowed CCAs to enter into BioMAT contracts and recover costs,[3] CCAs sponsored legislation to expressly authorize participation by CCAs in the BioMAT program. In 2021, the Legislature passed Assembly Bill ("AB") 843 to accomplish this purpose. Following the passage of AB 843, the Commission instituted Rulemaking ("R.").22-10-010 to examine CCA participation in the BioMAT program, noting that "AB 843 amended Public Utilities Code Section 399.20 to extend to CCAs within an [investor-owned utility's ("IOU")] service territory the existing renewable feed-in tariff for qualifying bioenergy electric generation facilities."[4]

CCA participation in the BioMAT program was extensively reviewed and addressed in R.22-10-010. Following a year-long process, the Commission issued D.23-11-084, which set rules to enable CCAs to participate in the BioMAT program. Consistent with guidance provided in D.23-11-084, on January 29, 2024, the California Community Choice Association ("CalCCA") submitted a Tier 2 joint advice letter seeking Commission approval of various BioMAT program documents on behalf of four initial CCA participants: Central Coast

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2 *See* RPS OIR at 17; Ordering Paragraph 7 (Appendix B).

3 *See* D.20-08-043 at 16-18.

4 OIR (R.22-10-010) at 1.

Community Energy, Orange County Power Authority, Pioneer Community Energy, and Redwood Coast Energy Authority. Subsequently, on February 1, 2024, each of these participating CCAs submitted a Tier 3 advice letter seeking Commission approval of program year 2024 and 2025 forecast BioMAT revenue requirements. As further described below, initial action taken to date by CCAs to investigate and participate in the BioMAT program has been extensive, and reflects a material changed circumstance in the BioMAT program.

Since its original adoption in 2014,[5] the BioMAT program has undergone review, revisions, and updates. With limited exception, the Commission has used the Renewables Portfolio Standard ("RPS") program rulemaking to review the BioMAT program and to address BioMAT-related issues. R.11-05-005 was the original venue for consideration of BioMAT-related issues.[6] Subsequent review of and revisions to the BioMAT program occurred within the context of successor RPS rulemakings (R.15-02-020 and R.18-07-003), including the most recent revision to the end date for the BioMAT program[7] and adoption of numerous "changes to program rules, contract terms, and processes."[8]

The BioMAT program was initially authorized for 60 months from program start date (or, until February 2021).[9] Following a staff proposal and stakeholder input, the end date for the program was subsequently extended to December 31, 2025.[10] In scoping issues for the Commission's implementation of AB 843 relating to participation by CCAs, the assigned

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5 *See* Decision ("D.")14-12-081.

6 *See* D.14-12-081.

7 *See* D.20-08-043 at 11.

8 *See* D.20-08-043 at 3-4 (summarizing an extensive list of program-related changes prompted by the *Bioenergy Market Adjusting Tariff (BioMAT) Staff Proposal*, dated March 5, 2020 ("BioMAT Staff Proposal")).

9 *See* D.14-12-081 at 71; *see also* D.16-10-025 at 4.

10 D.20-08-043 at 10.

Commissioner made clear that the Commission would not be using R.22-10-010 to consider "amendments to the sunset date."[11] This determination was made because of the belief that an RPS rulemaking is "the appropriate place to consider programmatic changes to BioMAT not explicitly required by AB 843" and because consideration in an RPS rulemaking "would enable participation of all BioMAT stakeholders."[12]

The Commission recently considered and renewed this determination. In D.24-01-033, the Commission addressed a long-pending petition for modification that sought, among other things, to extend the end date for the BioMAT program. The Commission denied the request but reaffirmed its position that "[t]he BioMAT program will continue to be monitored, reviewed, and revised, as necessary, in R.18-07-003 or its successor [RPS] proceeding."[13]

Purposeful review of the BioMAT program in this proceeding is warranted. Participation by CCAs in the BioMAT program represents a material changed circumstance that merits further review of the program. Moreover, current market and regulatory factors, and their impact on the BioMAT program, should also be reviewed. While the Joint BioMAT CCAs believe that the end date for the BioMAT program should be examined and revised as soon as possible, other changes to the program should also be considered in due order, as briefly described below.

II. OPENING COMMENTS

The RPS OIR expressly invites parties "to comment on the Preliminary Scoping Memo

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11 *Assigned Commissioner's Scoping Memo and Ruling*, issued on April 6, 2023 in R.22-10-010 ("CCA BioMAT Scoping Memo"), at 2.

12 CCA BioMAT Scoping Memo at 2.

13 D.24-01-033 at 5. A pending proposed decision in R.11-05-005 would also, if approved by the Commission, deny a request for an extension to the end date on procedural grounds. *See Proposed Decision of Administrative Law Judge Atamturk,* dated January 24, 2024, at 6 (Conclusion of Law 1).

and schedule established in th[e] OIR."[14] As noted above, the Preliminary Scoping Memo includes the following as an issue within the preliminary scope of this proceeding:

> "Ongoing monitoring, reviewing ***and revising***, as needed, all RPS procurement methods and tariffs, such as…the Bioenergy Market Adjusting Tariff (BioMAT)."[15]

For comments "directed to the issues identified within the preliminary scope of this proceeding," the RPS OIR directs parties to "include whether to revise the issues; how to prioritize the issues to be resolved; how procedurally to address these issues; and the proposed timeline for resolving the issues identified."[16] Set forth below, the Joint BioMAT CCAs address these matters with an initial focus on revising the BioMAT program by extending the end date from December 31, 2025 to mid-2029.

An extension of the end date should be considered on an expedited basis to provide reasonable assurance to participating CCAs that their timely efforts to launch their respective BioMAT programs will be duly recognized and accommodated, and to incentivize additional CCA participation. As it is now, notwithstanding expending significant cost and time to develop BioMAT program documents and to initiate implementation efforts, the current end date would unnecessarily truncate the contracting period for CCAs, particularly when compared to the contracting period for the IOUs when they launched their respective BioMAT programs.

Other changes to the BioMAT program should also be considered in this proceeding in due course. Consideration of other changes to the BioMAT program is reasonable in light of the recent emergence of CCAs as participants in the program, but also because key market and regulatory issues have arisen in the intervening years since the Commission's last review of the

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14 RPS OIR at 11.

15 OIR at 7; ***emphasis*** added.

16 OIR at 7.

BioMAT program. While still time sensitive, these other changes to the BioMAT program will likely require more time to consider than a simple extension to the program's end date.

A. The Preliminary Scoping Memo Should Be Revised to Expressly Include the Issue of Extending the BioMAT Program End Date

As noted above, the Preliminary Scoping Memo provides generically for consideration of revisions to the BioMAT program.[17] The Joint BioMAT CCAs request that the final Scoping Memo ***expressly*** include, as ***a distinct issue***, the question of whether to extend the BioMAT program's end date. Consideration of extending the end date is warranted in light of the recent emergence of CCAs as new participants in the program. By expressly identifying this issue, parties and stakeholders will be on notice that the Commission plans to address and consider whether to extend the end date.

B. The Schedule for this Proceeding Should Prioritize Consideration of the BioMAT Program's End Date

Expedited consideration of whether to extend the BioMAT program's end date is needed to address the uncertainty and unfair treatment currently facing CCAs. As evidenced by the extensive work put forth in recently submitted BioMAT-related documents, materials and tariffs, the participating CCAs are committed to successfully implementing the BioMAT program. The joint advice letter submitted on January 29, 2024 is over 300 pages, and contains a variety of detailed implementation-related documents and material. The participating CCAs made this commitment in the face of uncertainty associated with the program's end date. The Joint BioMAT CCAs request that the Commission work diligently to acknowledge the participating CCAs' commitment to date and to address the disadvantage embedded in the currently restricted participation window.

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[17] *See* note 15, above.

As it stands now, the Joint BioMAT CCAs face a program duration that differs markedly from what the IOUs experienced when they first launched their respective BioMAT programs. For the IOUs, the Commission determined in D.14-12-081 that it is "reasonable to set the ending date for the bioenergy [feed-in tariff] as being 60 months from the program starting date."[18] As the original end date (February 2021) was approaching, the Commission considered and extended the end date by another five years for the IOUs.[19] The staff proposal supporting this extension stated that "[e]xtending the end date by five years will provide more time to fulfill the SB 1122 requirement of 250 MW of procurement from small bioenergy projects."[20] The staff proposal also stated that "[a] five-year program extension should provide more long-term programmatic certainty and allow more time for additional project development, while maintaining the Commission's direction to establish a clear program end date."[21]

As such, the IOUs have received the benefit of successive five-year terms to contract for BioMAT projects. In contrast, as it stands now, the Joint BioMAT CCAs will have less than two years to contract for BioMAT projects. To be consistent with Commission goals, more "long-term programmatic certainty" is needed for participating CCAs.

C. The Commission Should Address the Issue of Extending the BioMAT Program's End Date Through Written Comments

The issue of the BioMAT program end date was addressed in the original BioMAT program decision (D.14-12-081) and again in D.20-08-043 (after being vetted in the BioMAT Staff Proposal). Moreover, this issue was also addressed in the context of a petition for

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18 D.14-08-021 at 71.

19 D.20-08-043 at 10.

20 BioMAT Staff Proposal at 2.

21 BioMAT Staff Proposal at 2.

modification.[22] As such, while certain aspects of the issue are unique (namely, recent participation by CCAs), the general issue has been examined previously. This should allow for expedited consideration without having to produce an extensive procedural record.

While the Joint BioMAT CCAs are not necessarily opposed to having a workshop at which CCAs and other parties could discuss the issue of extending the program end date, the Joint BioMAT CCAs do not believe that a workshop is necessary. In light of time constraints and the approaching end date, the Joint BioMAT CCAs believe that it would be best to address this issue through an administrative law judge ruling describing the issue (possibly coupled with a staff proposal) and requesting opening and reply comments on the issue.

D. The Commission Should Issue a Final Decision By September 2024 to Extend the BioMAT Program's End Date

As noted above, participating CCAs are currently facing unfair treatment vis-à-vis the IOUs with respect to program duration. Instead of having five years to implement the BioMAT program, participating CCAs have less than two years. In recognition of the significant commitment made by participating CCAs, the Joint BioMAT CCAs request that the Commission issue a final decision on an extended program end date by September 2024. If the scoping memo is issued in the first quarter, as contemplated in the OIR,[23] the proposed schedule in the OIR should allow for the orderly consideration of this issue in the second quarter, and issuance of a final decision in the third quarter.

For comparability, the Joint BioMAT CCAs recommend that CCAs be given five years to implement the BioMAT program. Given a program start date in mid-2024, this would mean that

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[22] *See* D.24-01-033 (addressing a petition for modification filed by the Bioenergy Association of California).

[23] *See* RPS OIR at 8.

the BioMAT program end date should be extended through mid-2029.

E. Other Changes to the BioMAT Program Should be Considered in the Context of the RPS Proceeding, and Addressed in the Early Stages of the Proceeding

In D.14-12-081, the Commission expressly set forth its expectation that various factors could and eventually would justify a review process for the BioMAT program – both with respect to pricing factors[24] and to the other factors influencing the BioMAT program.[25] In furtherance of this expectation, the Commission launched a major review process in 2017 that lasted roughly three years, culminating in the issuance of D.20-08-043.[26] While D.20-08-043 addressed many changes, the Commission declined to make a determination on "additional actions that the Commission should take to address program cost, program barriers, expanding program participation, safety, and/or equity."[27] Instead, the Commission stated that it would continue to monitor and revise the BioMAT program, as necessary.[28]

The Joint BioMAT CCAs believe that it is now appropriate for the Commission to initiate a second review of the BioMAT program. Two principal factors warrant this review. First, the emergence of CCAs as participants in the BioMAT program creates a material change to the program. As noted in the legislative analysis supporting final adoption of AB 843:

> When the BioMAT program was first established in 2012, there was only one CCA serving customers. There are now 23 CCAs that serve more than 11 million customers in the state. If enacted, this bill will allow a growing portion of the state's energy sector to participate in BioMAT.[29]

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[24] *See* D.14-12-081 at 62.

[25] *See* D.14-12-081 at 73-74.

[26] *See* D.20-08-043 at 6 (providing a description of the review process).

[27] D.20-08-043 at 53.

[28] *See* D.20-08-043 at 53.

[29] *Assembly Concurrence in Senate Amendments*, dated July 5, 2021, at 2.

The significant expansion of CCA programs over the last seven years and the commitment made recently by CCAs to the BioMAT program underscore the changing dynamic and the need to consider the BioMAT program in light of these changed circumstances.

Second, pricing trends suggest that a review is appropriate. In D.14-12-081, the Commission generally described the tension surrounding prices under the BioMAT program.[30] On the one hand, the Commission recognized concerns about "the costs to ratepayers of implementing [the BioMAT program]."[31] On the other hand, the Commission adopted the view expressed by a party that "in order to successfully implement [the legislatively mandated BioMAT program], the utilities will almost surely have to procure some very expensive power…"[32] To hold this tension in balance, the Commission established points and parameters "at which a review of the program pricing is appropriate."[33] Given current pricing and cost-related factors, the Joint BioMAT CCAs believe that a review of program pricing is necessary and appropriate.

III. CONCLUSION

The Joint BioMAT CCAs respectfully request that the issue of extending the BioMAT program's end date be set forth as a distinct issue in the final scoping memo, and that the schedule for this proceeding be established to provide for accelerated consideration of this issue based on written comments. The Joint BioMAT CCAs also request that other changes to the BioMAT program be included as a separate issue to be considered in this proceeding, ideally in the early stages of the proceeding.

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[30] *See generally* D.14-12-081 at 60-63

[31] D.14-12-081 at 61.

[32] D.14-12-081 at 61 (citing Green Power Institute).

[33] D.14-12-081 at 62.

The Joint BioMAT CCAs thank the Commission for its consideration of these requests.

Dated: March 1, 2024

Respectfully submitted,

/s/ Scott Blaising

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Attorney for the
Joint BioMAT Community Choice Aggregators

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

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

Company name/CPUC Utility No.: Marin Clean Energy (MCE)

Utility type:

- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Wade Stano
Phone #: 415-464-6024x104
E-mail: wstano@mceCleanEnergy.org
E-mail Disposition Notice to: wstano@mceCleanEnergy.org

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

March 15, 2024.

Advice Letter (AL) #: 74-E

Tier Designation: 3

Subject of AL: RE: Marin Clean Energy's Integrated Demand-Side Management Tier 3 Advice Letter from the Energy Efficiency Portfolio Administrators

Keywords (choose from CPUC listing): Energy Efficiency; Demand Side Management

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.23-06-055.

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: N/A

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

Confidential treatment requested? [ ] Yes [x] No

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

Resolution required? [x] Yes [ ] No

Requested effective date: 6/1/24

No. of tariff sheets: 0

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

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

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

Tariff schedules affected: N/A

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

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

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

Clear Form

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

California Public Utilities Commission Energy Division Tariff Unit Email: EDTariffUnit@cpuc.ca.gov	Contact Name: Wade Stano Title: Senior Policy Counsel Utility/Entity Name: Marin Clean Energy (MCE) Telephone (xxx) xxx-xxxx: (415) 464-6024x104 Facsimile (xxx) xxx-xxxx: Email: wstano@mceCleanEnergy.org
	Contact Name: Alice Havenar-Daughton Title: VP of Customer Programs Utility/Entity Name: Marin Clean Energy (MCE) Telephone (xxx) xxx-xxxx: (925) 378-6730 Facsimile (xxx) xxx-xxxx: Email: ahavenar-daughton@mcecleanenergy.org

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

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

March 15, 2024

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

MCE Advice Letter 74-E

RE: Marin Clean Energy's Integrated Demand-Side Management Tier 3 Advice Letter from the Energy Efficiency Portfolio Administrators

Pursuant to Decision ("D.") 23-06-055 *Decision Authorizing Energy Efficiency Portfolios for 2024-2027 and Business Plans for 2028-2031*; and guidance issued from the California Public Utilities Commission ("CPUC" or "Commission") on December 28, 2023, Marin Clean Energy ("MCE") hereby submits its Integrated Demand-Side Management ("IDSM") Tier 3 Advice Letter from the Energy Efficiency ("EE") Portfolio Administrators ("Advice Letter" or "AL") to request approval of MCE's proposed IDSM program for Program Years ("PY") 2024-2027 as MCE AL 74-E.

I. TIER DESIGNATION

This AL has a Tier 3 designation pursuant to Conclusions of Law ("COL") 41 and Ordering Paragraphs ("OP") 28-29 of D.23-06-055.

II. EFFECTIVE DATE

Pursuant to Section 7.3.5 G.O. 96-B, this Tier 3 AL will become effective immediately following the Commission's adoption of a Resolution. In support of improving summer reliability in 2024, MCE respectfully requests June 1, 2024, as the effective date of Commission approval.

III. BACKGROUND

MCE has administered EE funds under California Public Utilities Code ("Code") Section 381.1(a)-(d) since 2013. Pursuant to D.21-05-031, MCE filed its *Application of Marin Clean Energy for Approval of 2024-2031 Energy Efficiency Business Plan and 2024-2027 Energy Efficiency Portfolio Plan* ("MCE Application") with the Commission pursuant to Article 2 of its Rules of Practice and Procedure, California Public Utilities Code § 381.1 and D. 21-05-031 on March 04, 2022. On July 3rd, 2023, the Commission issued D.23-06-055 approving MCE's Application and allowing PAs to propose implementation of multi-distributed energy resource ("DERs") projects and receive rebates or incentives for non-EE IDSM measures through their portfolio programs in a Tier 3 Advice Letter by March 15, 2024.

D.23-06-055 approved MCE's EE portfolio for PY 2024-2027 with no adjustments to its proposed portfolio budget cap in the amount of $78,217,316.[1] D.23-06-055 approved all of MCE's proposed programs except for its PeakFLEXmarket program.[2] MCE filed its True-Up Advice Letter ("MCE AL 70-E") pursuant to D.23-06-055 on October 16, 2023. In MCE AL 70-E, MCE requested approval of its proposed EE budget amount of $76,670,990 for PYs 2024-2027 and submitted additional details on its EE portfolio consistent with Energy Division guidance. MCE proposed to allocate a fixed amount of $4 million from its 2024-2027 EE budget to an IDSM program.[3] The CPUC accepted MCE AL 70-E approving its proposed budget amount, IDSM allocation and portfolio details in a Disposition with the effective date of November 15, 2023.

The Commission explicitly promoted the integration of demand-side management measures in EE portfolios requiring the submission of comprehensive IDSM plans in the then upcoming EE applications in D.12-11-015[4] issued on November 15, 2012. In D.23-06-055, the Commission authorized portfolio PAs to spend up to 2.5 percent, or $4 million, whichever is greater, of its EE portfolio budget on load shifting strategies that reduce peak consumption on a pilot basis.[5] The Commission welcomed innovative approaches and allowed the combination of non-EE funds in IDSM programs if they have an EE component.[6] The Commission required PAs to list of any rules connected to non-EE funds incorporated into IDSM programs and details on measurement approaches in their Tier 3 ALs. The Commission additionally explicitly prohibited PAs from using EE funding for rebating capital costs of non-efficiency technologies.[7] The Commission further required PAs to document relevant cost categories in their annual EE reports.

On December 28, 2023, Energy Division served *Energy Division Guidance on Integrated Demand-Side Management (IDSM) Tier 3 Advice Letter Submissions from the Energy Efficiency Portfolio Administrators (PAs)* to interested parties of the Application ("A.") 22-02-005 et al service list detailing further direction on IDSM AL filings. The guidance directs PAs to propose "specific programs or propose the framework and structure for future multi-DER programs" and includes a template of questions.[8] The guidance notes that PAs will develop new measurement

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[1] *See* D.23-06-055 at p. 93 (Table 7).
[2] D.23-06-055 at pp. 103 (approving all non-discussed programs), 104-105 (stating general support for Peak FLEXmarket's approach, but failing to authorize additional funding).
[3] MCE AL 70-E at p. 8.
[4] D.12-11-015 at COL 43, 74 ("A consistent statewide IDSM approach for all utilities would better serve our integration objectives.").
[5] D.23-06-066 at pp. 78-79 (strategies to occur within programs launched during PYs 2024-2027 and also excluding event-based demand response), COL 41, OP 28-29.
[6] D.23-06-066 at p. 79.
[7] D.23-06-066 at p. 80.
[8] Energy Division Guidance on Integrated Demand-Side Management (IDSM) Tier 3 Advice Letter Submissions from the Energy Efficiency Portfolio Administrators (PAs), December 2023, at pp. 2, 5.

approaches and that Energy Division may refine its direction over time through iterative processes. The guidance concludes that IDSM programs have the potential to significantly advance California toward its full decarbonization goals.[9]

IV. PURPOSE

MCE requests approval of its proposed IDSM program, a Peak Flex Market Program, for PYs 2024-2027 in compliance with D.23-06-055. MCE submits a comprehensive strategy that integrates demand response and load shifting for both residential and commercial customers. MCE submits additional details on its IDSM program consistent with the Energy Division Guidance on Integrated Demand-Side Management ("IDSM") Tier 3 Advice Letter Submissions from the Energy Efficiency Portfolio Administrators ("PAs") issued by Energy Division ("ED") staff on December 28, 2023.

MCE submits the following attachment with MCE AL 74-E:

- Attachment A: *Integrated Demand-Side Management Energy Efficiency Portfolio Administrators Program Proposal for Program Years 2024-2027 - Proposed by Marin Clean Energy*.

MCE specifically includes the following sections in *Attachment A* to this filing:

- I. Introduction;
- II. Summary of MCE's IDSM Program – Peak Flex Market;
- III. Metrics;
- IV. Measurement and Verification;
- V. Goals for MCE's New Multi-DER IDSM Program; and
- VI. Compliance with Decision 23-06-055.

V. CONCLUSION

MCE respectfully requests the Commission approve its IDSM program, Peak Flex Market, within its EE portfolio for PYs 2024-2027.

VI. NOTICE

MCE served a copy of this AL via email on the official Commission service list for R.13-11-005 and A.22-02-005 et al on March 15, 2024.

For changes to these service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov or MCE Regulatory at regulatory@mcecleanenergy.org.

[9] *Id*. at p. 4.

VII. PROTESTS

Anyone wishing to protest this advice filing proposing MCE's IDSM program, Peak Flex Market, for PYs 2024-2027 may do so by letter via U.S. Mail, or electronically, any of which must be received no later than 20 days after the date of this advice filing on April 4, 2024. Protests should be mailed to:

> CPUC, Energy Division
> Attention: Tariff Unit
> 505 Van Ness Avenue
> San Francisco, CA 94102
> Email: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address as above).

In addition, protests and all other correspondence regarding this AL should also be sent electronically to the attention of:

Wade Stano
Senior Policy Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6024x104
Email: wstano@mceCleanEnergy.org

Alice Havenar-Daughton
VP of Customer Programs
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Phone: (925) 378-6730
ahavenar-daughton@mcecleanenergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

VIII. CORRESPONDENCE

For questions, please contact Wade Stano at (415) 464-6024x104 or by electronic mail at wstano@mceCleanEnergy.org.

/s/ Wade Stano

Wade Stano

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Appendices
Attachment A: *Integrated Demand-Side Management Energy Efficiency Portfolio Administrators Program Proposal for Program Years 2024-2027 - Proposed by Marin Clean Energy*.

cc: Service List for R.13-11-005; A.22-02-005 et al.

ATTACHMENT A

Integrated Demand-Side Management Energy Efficiency Portfolio Administrators Program Proposal for Program Years 2024-2027

Proposed by Marin Clean Energy

MCE Empowering Our Clean Energy Future
CONTRA COSTA | MARIN | NAPA | SOLANO

I. Introduction

The California Public Utilities Commission ("CPUC") or ("Commission") authorized an innovative opportunity for energy efficiency ("EE") program administrators ("PAs") to implement a Multi-Distributed Energy Resource ("Multi-DER") Integrated Demand Side Management ("IDSM") strategy in Decision ("D.") 23-06-055.[1] The Commission specifically approved "ongoing or permanent load shifting or load reduction."[2] MCE requested and the Commission approved $4,000,000 in IDSM funding within its EE portfolio for an IDSM program in program years ("PY") 2024-2027.[3] The Commission directed PAs to submit Tier 3 Advice Letters ("AL") on IDSM programs or frameworks pursuant to Energy Division Guidance.[4] MCE submits the following IDSM program details pursuant to D.23-06-055 and Energy Division Guidance for Commission approval.[5]

II. Summary of MCE's IDSM Program – Peak Flex Market

MCE proposes to adapt its existing Peak FLEXmarket program to implement a year-round IDSM program designed as a comprehensive strategy that offers demand response and load shifting for both residential and commercial customers. [6] MCE proposes to name this evolving program, "Peak Flex Market."

MCE started operating and self-funding its current Peak FLEXmarket program in 2021 as a "single season"[7] summer program (June 1 to October 31) focused on reducing peak electric demand from 4pm - 9pm Pacific Standard Time ("PST") through load shifting and demand response events. In D.21-12-011 the *Decision on Energy Efficiency Actions to Enhance Summer 2022 and 2023 Electric Reliability*, the Commission approved MCE's use of unspent EE funds to continue Peak FLEXmarket program operation in support of summer reliability goals in PYs 2022 and 2023.[8]

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[1] D.23-06-055 *Decision Authorizing Energy Efficiency Portfolios for 2024-2027 and Business Plans for 2028-2031*.
[2] D.23-06-055 OP 29 at p. 128.
[3] MCE AL 70-E at p. 8; CPUC, Marin Clean Energy's True-Up Advice Letter, Staff Disposition, February 2024 (Disposition accepted effective November 15, 2023).
[4] December 28, 2023, Energy Division served *Energy Division Guidance on Integrated Demand-Side Management Tier 3 Advice Letter Submissions from the Energy Efficiency Portfolio Administrators* to A.22-02-005 et al Service List.
[5] *See* MCE AL 74-E at pp. 1-3 (for additional procedural and regulatory background information).
[6] *See* MCE, FLEXmarket Program, available at: https://www.mcecleanenergy.org/peak-flexmarket/ ("Peak FLEXmarket").
[7] "Single season" refers to projects shows impacts are limited to the summer peak timeframe in which they were measured, and for which there is no effective useful life, which is a dominate driver of TSB value in energy efficiency.
[8] *See* D.21-12-011 *Energy Efficiency Actions to Enhance Summer 2022 and 2023 Electric Reliability OP 2* at p. 60.

MCE proposes to adapt its previously single season program design[9] to year-round load shifting and load reduction during peak hours—the Peak Flex Market program.[10] MCE proposes this adjustment because a single-season program design more easily captures total system benefit ("TSB") within the current EE cost effectiveness tool ("CET") and advances EE portfolio goals. In compliance with D.23-06-055, MCE's Peak Flex Market program will not offer incentives to offset the capital cost of acquiring new equipment.[11] MCE will leverage existing and new equipment installed through normal market conditions or through other programs, such as the MCE Energy Storage program, and encourage aggregators[12] to maximize grid benefits by redistributing daily energy use away from peak demand hours of 4pm – 9pm PST. MCE proposes to continue offering its Peak Flex Market program with the required adjustments described in this AL 74-E and to use the approved $4 million IDSM funding to exclusively support permanent daily load shifting and reduction activities.[13] MCE will offer two distinct participation options for aggregators, daily load reduction or demand response. Offering two distinct participation options will allow MCE to maintain a clear separation from the event-based demand response aspect of the program, that will continue to be funded through MCE's Operational Funds.[14]

MCE's Peak Flex Market program will leverage similar participation and measurement and verification ("M&V") frameworks as MCE's existing Commercial and Residential Efficiency Market programs,[15] that leverage market access principles, population-level normalized-metered energy consumption ("NMEC"), and the avoided cost calculator ("ACC") to align program payments with TSB and cost-effective EE savings. The Peak Flex Market program will incentivize aggregators with demand and load management capabilities for delivered daily load reduction during hours with high avoided cost value. Many of the measures MCE anticipates enrolling in the program, battery energy storage systems ("BESS") or managed EV charging, for example, will have the ability to shift demand to hours with lower avoided cost values. The avoided cost value from hours where usage increases will be subtracted from the avoided cost value in hours where usage decreases to determine the program's TSB. Just as in MCE's Commercial and Residential Efficiency Market programs, MCE will tie incentives to the TSB after accounting for administrative costs which will result in a cost-effective program deployment.

MCE anticipates IDSM equipment and measures will vary by aggregator and customer. The program encourages measures including, but not limited to energy storage, managed EV charging, building automation systems and other behavioral interventions. Solar PV, other on-site electricity

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[9] MCE's Peak FLEXmarket.
[10] MCE defines "peak hours" as 4pm Pacific Standard Time until 9pm Pacific Standard time.
[11] D.23-06-55 at p. 80.
[12] MCE defines "Aggregators" as participating vendors or program partners who have demand and load management capabilities for an aggregated group of customers.
[13] CPUC, Staff Disposition of MCE AL 70-E, February 2024 (effective November 15, 2023).
[14] MCE's Operational Funds do not include ratepayer funds issued by the Commission.
[15] *See* MCE, FLEXmarket Programs, available at: https://www.mcecleanenergy.org/flexmarket/ (MCE's Commercial & Residential Efficiency Market programs).

generation, and fossil-fuel technologies such as back-up diesel generators or gas-fired solutions will not be eligible.

MCE anticipates using device level data, meter data and sub-meter data to evaluate Peak Flex Market program performance in combination with the ACC to align payments with grid benefits and TSB value delivered. MCE will design program payments to not exceed the TSB of enrolled projects, which establishes a cost-effective floor for program expenditures. This pay-for-performance ("P4P") structure tied to the ACC sends a price signal that prioritizes distributed energy resources ("DERs") that achieve the greatest daily load reduction during the most valuable peak hours throughout the year. MCE's Peak Flex Market program design encourages appropriate scheduling and operation of existing equipment to maximize benefits and TSB value.

Under the Peak Flex Market program model, MCE will continue to engage with a lead implementer responsible for aggregator management and implementation of the program. MCE will determine customer eligibility requirements and aggregators will lead customer engagement. MCE will compensate participating aggregators for the TSB value they deliver for customers within MCE's service area. As a ratepayer funded program, MCE will not restrict customer eligibility to MCE generation customers, the program will be open to both MCE and PG&E customers alike.

III. Metrics

MCE plans to assess the program performance and participation of the Peak Flex Market program annually to determine appropriate budget allocations in future portfolios. Where possible, MCE will align reporting with existing energy efficiency reporting processes and timelines.[16]

MCE proposes the tracking and reporting of the following program metrics and indicators for enrolled projects in its Energy Efficiency Annual Report:

- Number of enrolled residential and non-residential projects;
- Forecasted annual load reduction out of peak hours (4pm-9pm) (kWh);
- Forecasted program TSB ($);
- Forecasted payments to aggregator ($);
- Total measured load reduction out of peak hours (4pm-9pm) (kWh);
    - Summer Months (June 1 – Oct 31);
    - Non-Summer Months (all months excluding June 1- October 31);
- Program TSB to date ($);
- Payments to aggregator to date ($);
- Incentives to customers ($);
- Total budget reserved ($); and
- Total budget remaining ($).

[16] CPUC, CEDARS, available at: https://cedars.sound-data.com/. The reporting timelines can be accessed by logging in to a CEDARS account. Once logged in, reporting timelines are listed on the homepage.

In the Metrics section, *Energy Division Guidance on IDSM* directs PAs to outline concerns "regarding the new programs or framework."[17] MCE submits concerns on sufficiently claiming and reporting the anticipated load reduction impacts within the current limitations of the CET. To mitigate this concern, MCE proposes the following approach to resolve those concerns. MCE will leverage existing tools developed for prior iterations of the Peak Flex Market program to calculate TSB for the enrolled projects. Most projects that quality for this program will result load reduction during periods of high avoided costs and load increase during periods of low avoided cost. Existing program tools will enable MCE to quantify the positive benefits associated with load reduction during high avoided cost hours and the negative benefits associated with load increase during low avoided cost hours. The sum of both will represent the program's total benefits. This type of custom load shape calculation, which fully captures the benefits associated with load shifting and load reduction, is not possible with the current CET because it only accepts *deemed* load shapes. Custom load shape calculations are foundational to capturing and compensating for the value created by the Peak Flex Market program. This approach is vital to verifying "ongoing or permanent load shifting or load reduction."[18]

In order to generate claimable benefits and determine the cost effectiveness of this program, MCE proposes to input the custom TSB values derived from the tool described above into the claims input file. To do so requires the addition of a field in the claims input file to account for the load-shifting benefit, similar to the present approach developed by CPUC staff to claim benefits from low global warming potential refrigerants.

MCE also submits an additional concern on potential dual enrollment in other similar programs resulting in the double counting of results. To address this concern, the Peak Flex Market program will require aggregators and customers to self-report participation in another EE/demand response ("DR") programs. Dual enrollment in other DR programs will not be allowed unless a specific process for disaggregating impacts is identified and included in an Implementation Plan ("IP").

MCE appreciates the CPUC's continued efforts to require IOUs to share DR program participation data to minimize the concern with dual enrollment and encourages further supportive efforts. MCE's approach to disaggregating Energy Efficiency Program impacts is described below.

IV. Measurement and Verification

MCE established the Peak FLEXmarket program to increase customer participation in daily load shifting by measuring and paying for energy impacts and load modification that (a) currently do not traditionally fit within an EE program framework; or (b) are incremental to savings which accrue under other MCE EE programs. Leveraging this opportunity unlocks new value for aggregators to continue to drive grid benefits and customer engagement.

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[17] December 28, 2023, Energy Division served *Energy Division Guidance on Integrated Demand-Side Management Tier 3 Advice Letter Submissions from the Energy Efficiency Portfolio Administrators* to A.22-02-005 et al Service List at p. 2 (List Item 4).
[18] D.23-06-055 OP 29 at p. 128.

MCE proposes implementing the following approaches and methodologies outlined below in its Peak Flex Market program to measure impacts, optimize TSB benefits, and disaggregate the results from other deemed and custom EE programs. MCE will use different approaches to quantify and disaggregate the daily load reduction impacts of enrolled sites depending on whether the load shifting impacts are derived from existing equipment, new equipment or equipment for which device level data is available. However, the program may encounter other scenarios that MCE will assess on a case-by-case basis for program enrollment. Any further updates to the Peak Flex Market program's M&V methodology will be included in future IP updates.

A. Baselines

For the purposes of this program, MCE defines existing equipment as equipment installed prior to the program enrollment date with enough post-install operational data to establish a post-install baseline. This could include, but is not limited to, optimization of heating, ventilation and air conditioning ("HVAC"), lighting, behavioral or building controls. Once an aggregator enrolls a project of this type, a baseline will be established utilizing historical energy consumption data, weather normalization, and temporal patterns to predict energy usage in the absence of the program's intervention. MCE will use CalTRACK's[19] guidelines for selecting relevant weather stations and adjusting for weather conditions to establish accurate baselines for load shifting and load reduction scenarios. After establishing the baseline, MCE will utilize CalTRACK's statistical models to analyze shifts in energy usage patterns, especially during peak and off-peak periods, to quantify the impact of load shifting interventions.

Equipment lacking sufficient post-install data to establish a new baseline will be considered newly installed equipment. Similar to the first approach outlined above, MCE will employ CalTRACK to establish a pre-install baseline and measure performance using consumption data. If the equipment was installed through an EE program that utilizes custom and deemed methodologies, MCE will remove any EE savings already accrued to these EE programs to measure and pay for only the incremental impacts associated with additional load reduction. Newly installed BESS will be credited for total energy charged and discharged. MCE anticipates further refining of this approach in close collaboration with Energy Division staff to ensure appropriate attribution of impacts. MCE will provide additional M&V details in the program IP.

Equipment currently enrolled in MCE's Commercial and Residential Efficiency Market programs, or similar programs, is not eligible for participation in the Peak Flex Market IDSM program as custom load shapes and metered impacts are already captured and reported within these programs.

B. Data Sources

MCE will use sub-meter data and device level telemetry when available, this includes but is not limited to, BESS, thermal storage and electric vehicle/electric vehicle supply equipment

[19] CalTRACK, CalTRACK Technical Documentation, available at: https://docs.caltrack.org/en/latest/.

("EV/EVSE"). When sub-meter data or device level telemetry is not available, MCE will use advanced metering infrastructure ("AMI") data to quantify load shifting.

C. Disaggregating DR Impacts

The Peak Flex Market program has two distinct participation pathways (a) daily load reduction or (b) event-based demand response. Enrollment in both pathways will not be permitted at the onset of the program; therefore, a disaggregation of impacts between load reduction and DR events is not needed. This design maintains a clear separation between the program's load shifting and load reduction pathway funded through IDSM funding and the event-based demand response funded through MCE's Operational Funds.

Through these approaches the Peak Flex Market program will utilize meter, device level, and sub-meter data to measure load reduction impacts, evaluate performance, and disaggregate impacts from other EE programs. The program will leverage population-level NMEC and CalTRACK principles where applicable and apply all impacts to the ACC to align program payments with grid benefits and TSB value delivered. MCE will further detail the M&V, methodologies, baselines, and approaches the program intends to implement in its forthcoming IP as further described in **Section V. Goals for MCE's New Multi-DER IDSM Framework**.

V. Goals for MCE's New Multi-DER IDSM Program

The intended outcome of MCE's Peak Flex Market program is to achieve permanent load reduction during the peak hours of 4pm - 9pm by incentivizing aggregators to optimize customer load shapes to redistribute daily energy usage away from these peak hours using existing or newly installed technologies. An annual performance period that ties payments to delivered TSB further encourages the appropriate scheduling and operation of existing equipment to maximize impacts and grid value.

MCE plans to relaunch the adjusted Peak Flex Market program within 90 days following Commission approval.[20] MCE will leverage existing relationships with aggregators and customers to support an efficient program launch. MCE anticipates the Peak Flex Market program will have immediate uptake from aggregators and customers who participated in the previous iteration of the program. Adjusting the Peak FLEXmarket program into the new Peak Flex Market program to capture year-round daily load reductions during the peak hours of 4pm-9pm produces an increased value add and opportunity for greater customer participation. MCE reviewed past program participation, approved budgets, and market potential to develop the following targets for the program submitted below in *Table 1*. MCE plans to assess program performance and participation annually to determine appropriate budget allocations for future portfolios.

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[20] MCE submits AL 74-E as Tier 3 advice letter per GO 96-B and subject to disposition under General Rule 7.6.2 (effective only after Commission approval and resolution required).

Table 1: Peak Flex Market Program Annual Program Goals

Metric	2024[21]	2025	2026	2027
Peak Load Shifted Outside 4pm-9pm (net kWh)	1,100,000	4,500,000	5,800,000	6,500,000
Total System Benefit	$200,000	$750,000	$1,000,000	$1,200,000

MCE will align reporting with existing energy efficiency reporting processes and timelines.[22] For metrics/indicators outside of EE reporting processes and timelines, MCE proposes the tracking and reporting of the program metrics and indicators for enrolled projects in its Energy Efficiency Annual Report.

VI. Compliance with Decision 23-06-055

MCE's Peak Flex Market program will comply with the requirements of D.23-06-055, and the *Energy Division Guidance on Integrated Demand-Side Management Tier 3 Advice Letter Submissions from the Energy Efficiency Portfolio Administrators* provided by Energy Division on December 28th, 2023.[23]

The Peak Flex Market program will provide incentives for load shifting only. MCE confirms, in compliance with D.23-06-055, MCE will not use any CPUC IDSM funds for event-based DR nor will IDSM funds or for capital project cost upgrades.[24]

- 1. Scope of Program and Technologies Used:
    - *See* **Section II**. **Summary of MCE's IDSM Program – Peak Flex Market.**[25]
- 2. Coordination with Other DER Proceedings
    - MCE does not presently receive funding from other CPUC programs or proceedings that it will combine with its Peak Flex Market program.[26]

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[21] 2024 goals are dependent on the timing of approval and subsequent program launch.
[22] CPUC, CEDARS, available at: https://cedars.sound-data.com/.
[23] As stated above in **Section II. Summary of MCE's IDSM Program – Peak Flex Market** at pp. 1-3, MCE will maintain a clear separation from the event-based demand response aspect of the program, that will continue to be funded through MCE's Operational Funds. MCE's Operational Funds do not include ratepayer funds issued by the Commission.
[24] D.23-06-055 at OP 29 (prohibiting funding event-based measures).
[25] MCE AL 74-E Attachment A at pp. 1 - 3.
[26] MCE specifically confirms it is not combining funds received and spent pursuant to D.21-12-011 (OP 2).

- 3. Funding Requirements
    - As of the date of this filing, MCE's Peak Flex Market program correspondingly[27] is not subject to additional Commission funding rules or requirements outside of EE and IDSM.
    - MCE supports layering complementary programs and outside funds to deliver greater benefits to ratepayers and judiciously using ratepayer funds. MCE commits to continuing to actively research and when appropriate, pursue additional funds for layering with its Peak Flex Market program.
    - If MCE receives complementary and appropriate funds for its Peak Flex Market program, MCE will integrate additional funding sources and will adhere to any controlling CPUC rules and guidance.
- 4. Ex Ante Assumptions:
    - *See Table 2* – Consistency with EE.[28]
- 5. Ex Post Processes:
    - *See Table* 2 – Consistency with EE.[29]
- 6. Project Cost Methodology:
    - *See Table* 2 – Consistency with EE.[30]
- 7. Reporting Process and Timeline:
    - *See* **Section II. Metrics** and **Section III. Measurement and Verificatio**n.[31]

Table 2: Energy Division Guidance on Integrated Demand-Side Management (IDSM) Tier 3 Advice Letter Submissions from the Energy Efficiency Portfolio Administrators (PAs) December 28, 2023

Scope	**Program or Framework**	***PA to complete***
	Technologies	BESS, thermal storage, EVSE, building automation, BROs
	Programs (or types)	Peak Flex Market - Integrated Demand Side Management Program
Approach to Coordination with other DER Proceedings	Proceeding(s) (one per cell)	Not applicable.
	Relevant Rules for Implementation from Proceeding	Not applicable.

[27] *See* **Section II. Summary of MCE's IDSM Program – Peak Flex Market** at pp. 1-3 (MCE presently proposes combining MCE Operational Funds).
[28] MCE AL 74-E Attachment A at p. 9.
[29] MCE AL 74-E Attachment A at p. 9.
[30] MCE AL 74-E Attachment A at p. 9.
[31] MCE AL 74-E Attachment A at pp. 3-6.

	Rules for Exemptions or Deviations (if applicable)	Not applicable.
	Funding requirements	Not applicable.
	Approach to draw from each funding source	Not applicable.
	New methods to show stacking of costs	Not applicable.
	Reporting Requirements (incl timing)	Not applicable.
	Procedural Path for access to funding.	Not applicable.
Consistency with EE	Ex Ante assumptions for energy efficiency reporting such as project benefits, measurement methods, baseline, and effective useful life ("EUL").	● Population-level NMEC control groups and approved documented NTG ratios tailored by sector.[32] ● EULs/RULs[33] of at least one year of load reduction potential. ● A weighted EULs/RULs will be reported based on the technology mix of enrolled projects.
	Ex Post process: project benefits, measurement methods, list of applicable measurement protocols, project costs, and methodology.	● Load reduction will be measured using sub-meter data, device level telemetry, or AMI data with population-level NMEC and CalTRACK methods where applicable. ● Achieved TSB will be a function of electricity consumption shifted out of peak hours, climate zone, metered load shape, EUL, and the ACC. ● Measure cost will not be included in cost effectiveness calculations per IDSM guidelines prohibiting funding capital project/measure upgrades.[34]

DATED: March 15, 2024.

[32] CPUC, Resolution E-4952 Approval of the Database for Energy-Efficient Resources updates for 2020 and revised version 2019 in Compliance with D.15-10-028, D.16-08-019, and Resolution E-4818 at p. A-45 (table of NMEC NTG ratios).
[33] Remaining Useful Life.
[34] D.23-06-055 at OP 29 (prohibiting funding of event-based measures).

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

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 24-01-017

**COMMENTS OF THE JOINT PARTIES ON
ORDER INSTITUTING RULEMAKING TO CONTINUE IMPLEMENTATION AND ADMINISTRATION, AND CONSIDER FURTHER DEVELOPMENT, OF CALIFORNIA RENEWABLES PORTFOLIO STANDARD PROGRAM**

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Dated: March 4, 2024

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 24-01-017

COMMENTS OF THE JOINT PARTIES ON ORDER INSTITUTING RULEMAKING TO CONTINUE IMPLEMENTATION AND ADMINISTRATION, AND CONSIDER FURTHER DEVELOPMENT, OF CALIFORNIA RENEWABLES PORTFOLIO STANDARD PROGRAM

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the *Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program* ("OIR"), issued on February 1, 2024, Apple Valley Choice Energy, City of Lancaster, City of Pico Rivera, City of Rancho Mirage, City of Pomona, City of San Jacinto, City of San José, Administrator of San José Clean Energy, City of Santa Barbara, Marin Clean Energy, Peninsula Clean Energy Authority, Silicon Valley Clean Energy Authority, Sonoma Clean Power, and the Regents of the University of California ("Joint Parties") respectfully submit these comments.[1]

The Joint Parties generally support the preliminary scoping memo as set forth in the OIR, but provide two recommended additions:

- The Scoping Memo should expressly include consideration of fully or partially combining the renewables portfolio standard ("RPS") Procurement Plan filing with the

[1] Pursuant to Rule 1.8(d), Apple Valley Choice Energy, City of Pomona, City of San José, Administrator of San José Clean Energy, City of Santa Barbara, Marin Clean Energy, Peninsula Clean Energy Authority, Silicon Valley Clean Energy Authority, Sonoma Clean Power, and the Regents of the University of California have authorized the undersigned counsel to sign and file these comments on their behalf.

integrated resource planning ("IRP") filings, consistent with the direction of Decision ("D.") 19-12-042; and

- The Scoping Memo should include consideration of a modification to the confidentiality rules for Final RPS Procurement Plans to ensure that the confidential information of retail suppliers is provided with three years of protection, consistent with D.21-11-029.

I. COMMENTS ON THE OIR

A. **The Scoping Memo Should Include Consideration of Fully or Partially Combining the RPS Procurement Plan Filing with the IRP Filings.**

The preliminary scoping memo in the OIR appropriately includes "[c]oordinating with the integrated resource planning proceeding," as a remaining issue from Rulemaking ("R.") 18-07-003.[2] One of the key unresolved issues regarding this coordination is the proposal to consider the full or partial combination of the RPS Procurement Plan filing with the IRP filings. The *Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2019 Renewables Portfolio Standard Procurement Plans* ("2019 ACR"), issued on April 19, 2019, included a Commission staff proposal to combine the RPS Procurement Plan filings with the IRP filings in years where IRP Plans are required.[3] In response, the large investor owned utilities ("IOUs") filed comments providing a detailed framework to accomplish combining these RPS and IRP filings.[4] Informed by the IOU proposal and other party comments, the Commission included the following direction in the decision adopting 2019 RPS Procurement Plans (D.19-12-042):

> It is always our goal to avoid duplicative filings and reduce the burden on small parties or new market entrants. We therefore direct Energy Division to develop a comprehensive and practicable plan to combine IRP and RPS filings without jeopardizing the current timelines, allocation of Commission resources, or procedural efficiencies currently in place for IRP and RPS. The plan must include

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[2] OIR at 7.
[3] 2019 ACR at 23-27.
[4] Joint Opening Comments of Southern California Edison Company (U 338-E), San Diego Gas & Electric Company (U 902-E), and Pacific Gas and Electric Company (U-39 E) on Coordination of RPS Procurement Plan With Integrated Resource Plan Proceeding, July 19, 2019.

> implementation details and identify the ways in which the combined IRP and RPS filing will meet the objectives identified in party comments (as listed above). To this end, Energy Division is authorized to hold workshops, establish working groups, prepare a white paper or staff proposal, and take such other actions as the Director of Energy Division may deem necessary. The Director of Energy Division shall issue progress reports on a quarterly basis and shall complete a staff proposal based on the foregoing process no later than August 2020.[5]

The Joint Parties agree with D.19-12-042 that the potential to avoid duplicative filings and reduce administrative burdens merits the consideration of a full or partial combination of the RPS and IRP filings. Therefore, the Joint Parties recommend that the Commission include in the Scoping Memo a process consistent with the direction of D.19-12-042. At a minimum, this should include an Energy Division-led process involving significant opportunities for input from parties to this proceeding. Given the complexity of this task and the importance of these filings, the proposed schedule for this process should provide adequate time for a thorough vetting of the ultimate proposal in order to ensure that the goals of reduced administrative burdens are actually achieved.

B. The Scoping Memo Should Include Consideration of a Modification of the Confidentiality Rules to Ensure Retail Sellers Receive Three Full Years of Confidentiality Protection.

D.21-11-029 revised the Commission's rules regarding confidentiality for certain RPS information. Specifically, D.21-11-029 shortened the confidentiality protection period for energy and capacity forecast data from a total of four years to three years, specifically limiting confidentiality to two future years and the "current year or year of filing."[6] Throughout D.21-11-029, the Commission reiterated its intent to provide retail sellers with a total of ***three years*** of confidentiality protection.[7] The *Administrative Law Judge's Ruling Regarding the Motions for*

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[5] Decision on 2019 Renewables Portfolio Standard Procurement Plans, December 30, 2019, at 74.
[6] D.21-11-029 at 2; *see also* D.21-11-029, Attachment 2, Appendix 2 at I(A) and I(B).
[7] *See id.* at 2, 34, 38, and 67.

Leave to File Confidential Material Under Seal ("2023 ALJ Confidentiality Ruling"), issued on June 12, 2023, provided further guidance on this direction from D.21-11-029 for Final RPS Procurement Plans as follows:

> the "current year (year of filing)" should be the year the document is filed. As a result, retail sellers' 2022 data in their final RPS procurement plans, filed in 2023, should not be redacted.[8]

In practice, the interpretation provided in the 2023 ALJ Confidentiality Ruling results in less than the full three years of confidentiality protection for retail seller energy and capacity data. This is due to the normal filing schedule where Draft RPS Procurement Plans are filed between May and August of the initial year and Final RPS Procurement Plans are typically due in January or February of the following year. For example, in the 2023 Draft RPS Procurement Plans (due July 17, 2023), retail sellers were entitled to confidentiality protection for data covering the years of 2023, 2024, and 2025. Final 2023 RPS Procurement Plans were due on January 22, 2024, and retail sellers filing on that date would lose the ability to redact 2023 data because the "year of filing" is now 2024. However, those retail sellers are presumably unable to redact 2026 data because this data was already made public in the Draft 2023 RPS Procurement Plans. As a result, these retail sellers are only able to redact 2024 and 2025 data in their Final 2023 RPS Procurement Plans. As 2023 data was only protected for approximately six months, the result is that retail sellers are only entitled to 2.5 years of confidentiality protection, rather than the full three years specified by D.21-11-029.

The Joint Parties request that the Commission include in the Scoping Memo the consideration of a modification to the confidentiality rules to address this misalignment.

[8] 2023 ALJ Confidentiality Ruling at 3.

II. CONCLUSION

The Joint Parties appreciate the opportunity to provide these comments on the OIR.

March 4, 2024,

Respectfully submitted,

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

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
And Related Matters.	A.22-05-023 A.22-05-024

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND CITY AND COUNTY OF SAN FRANCISCO ON THE PROPOSED DECISION MODIFYING GREEN ACCESS PROGRAM TARIFFS AND ADOPTING A COMMUNITY RENEWABLE ENERGY PROGRAM

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March 25, 2024

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TABLE OF CONTENTS

TABLE OF AUTHORITIES

SUBJECT INDEX OF RECOMMENDED CHANGES

Pursuant to Rule 14.3(b) of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the Joint CCAs provide the following Subject Index of Recommended Changes in support of the Opening Comments on the Proposed *Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program* ("Proposed Decision" or "PD"). The Joint CCAs recommend that the Proposed Decision be revised to:

- Clarify how interested community choice aggregators ("CCAs") should participate in the newly adopted community renewable energy program.
- Increase the Disadvantaged Communities Green Tariff ("DAC-GT") capacity cap for *all* CCA Program Administrators, not just those with contracted new capacity as of October 2023.
- Ensure the consolidation of the DAC-GT and Community Solar Green Tariff ("CSGT") programs protects existing CSGT customers and projects.
- Remove the creation of a central marketing website.
- Clarify that investor-owned utility ("IOU") and CCA tariffs need not be uniform.
- Remove the adoption of auto-enrollment for the modified DAC-GT.
- Clarify timing and applicability of existing program rules.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
And Related Matters.	A.22-05-023 A.22-05-024

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND CITY AND COUNTY OF SAN FRANCISCO ON THE PROPOSED DECISION MODIFYING GREEN ACCESS PROGRAM TARIFFS AND ADOPTING A COMMUNITY RENEWABLE ENERGY PROGRAM

I. INTRODUCTION

Pursuant to Rule 14.3 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Ava Community Energy ("Ava")[1], Clean Power Alliance of Southern California ("CPA"), the City and County of San Francisco, acting by and through its Public Utilities Commission ("CleanPowerSF"), Lancaster Choice Energy ("LCE"), Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority ("PCE"), Pico Rivera Innovative Municipal Energy ("PRIME"), San Diego Community Power ("SDCP"), San Jacinto Power ("SJP"), and San José Clean Energy ("SJCE") (collectively, the "Joint Community Choice Aggregators" or "Joint CCAs")[2] hereby submit these comments on the proposed *Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program*, issued on March 4, 2024 ("Proposed Decision" or "PD").

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1 Previously East Bay Community Energy ("EBCE"). Ava filed its Notice of Party Name Change on January 17, 2024.
2 *See* PD at 15 fn. 22; The PD erroneously excluded CleanPowerSF from the list of Joint CCAs.

The Joint CCAs generally support the Proposed Decision's conclusions regarding the modification of the Disadvantaged Communities Green Tariff ("DAC-GT") program. The Joint CCAs greatly appreciate the level of detail and consideration included in the PD in its evaluation of existing Green Access Programs as directed in Assembly Bill ("AB") 2316.[3] Nonetheless, the Joint CCAs do see several places where clarifications and corrections of factual and legal errors are necessary.

II. DISCUSSION

A. The Proposed Decision Should Provide Clarity on How Interested CCAs Should Participate in the Newly Adopted PURPA Compliant Community Renewable Energy Program

As directed in AB 2316, the PD determines that it is beneficial for the Commission to establish a new community renewable energy program.[4] Accordingly, the PD adopts a community renewable energy program that builds on current Public Utility Regulatory Policies Act ("PURPA") compliant tariffs.[5] Specifically, the PD states that "the adopted community renewable energy program will use the current PURPA compliant tariffs (ReMAT and the PURPA Standard Offer Contract or any other existing PURPA-compliant wholesale tariffs as identified by Utilities) as a foundation and layer on a subscription model."[6] In describing the new program, the PD notes that "[t]o reduce administrative costs and minimize market, education, and outreach costs while also reducing barriers to access, low-income subscribers meeting each Utility or CCA's Arrearage Management Program enrollment criteria will be prioritized for automatic enrollment" and that "[t]hese low-income customers will be automatically enrolled by

3 Codified in Pub. Util. Code Section 769.3.
4 Proposed Decision at 145-146.
5 *Id*. at 118.
6 *Id*. at 120.

their utility or participating CCA…"[7] Based on this language, and the PD's conclusion that all customers will be eligible to enroll as subscribers in this tariff,[8] it is clear that CCAs may participate in the newly created community renewable energy program. Additionally, Pub. Util. Code Section 769.3(b)(2)(B) provides that each CCA and electric service provider shall notify the Commission whether it will participate in a newly created community renewable energy program within 180 days of the establishment of the program, indicating the statutory requirement that a newly created program be open to CCAs.[9] Previous proposals in this proceeding for a new program recognized this requirement by detailing CCA participation in those proposals.[10] However, it is unclear how interested CCAs should participate in the new programs as proposed in the PD. The PD notes that "the Commission has several existing tariffs that are PURPA compliant,"[11] and includes "any other existing PURPA-compliant wholesale tariffs as identified by the Utilities"[12] within the new program.

Unfortunately, the PD does not expressly state that CCAs may create and/or use already-existing tariffs for the new program. Clarification that use of such tariffs is permissible is important. The PD observes that the adopted community renewable energy program would take advantage of several state and federal funds such as the Environmental Protection Agency's Solar for All funding.[13] The PD further adopts the use of $33 million appropriated to the Commission for community solar usage and storage-backed renewable generation programs as an adder for the low-income households as part of the new community renewable energy

[7] *Id*. at 121-122.
[8] *Id*. at 166, Ordering Paragraph ("OP") 1(d).
[9] Pub. Util. Code Section 769.3(b)(2)(B).
[10] *See generally* Exhibit CCSA-001 (Smithwood); Exhibit CCSA-007 (Smithwood).
[11] Proposed Decision at 118.
[12] *Id*. at 120.
[13] *Id*. at 121.

programs.[14] However, the PD does not outline a process for CCAs to access external funds or discuss Solar for All money supplementing the modified DAC-GT programs.

The Joint CCAs understand that there will be subsequent rulings and decisions included in this proceeding that will further develop the record with regards to the newly created community renewable program.[15] Specifically the PD notes that a future ruling would discuss bill credits for the new program.[16] However, the Joint CCAs believe there are additional outstanding questions that can, and should, be addressed as part of this future ruling as well. The Joint CCAs request that the PD be revised to (i) confirm that interested CCAs may create and utilize their own tariffs for the new program, (ii) clarify how CCAs can access external funds to serve their customers, and (iii) clarify when CCAs must notify the Commission of their participation in accordance with Pub. Util. Code Section 769.3(b)(2)(B). Alternatively, the Joint CCAs request that the PD be revised to ensure that this issue is included for discussion in upcoming rulings.

B. The Proposed Decision Should be Revised to Increase the DAC-GT Capacity Cap for All CCA Program Administrators

The Joint CCAs strongly support the PD's conclusion to increase the capacity allocations for the DAC-GT program to reach the Pub. Util. Code Section 769.3 goal of promoting robust participation by low-income customers.[17] In support of this conclusion, the PD states that the decision "adopts the Joint CCA's proposal to increase capacity allocations for those DAC-GT Program Administrators whose collective capacity cap is close to being fully procured within a particular utility service territory and allow to enroll an additional 50 percent of eligible

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14 *Id*. at 120-121.
15 *Id*. at 122 ("A future ruling in this proceeding will allow for additional record development.").
16 *Id*.
17 *Id*. at 137.

customers."[18] This would result in 37.316 MW of additional DAC-GT capacity before consolidation with the community solar green tariff ("CSGT") program.[19] However, the Joint CCAs had previously suggested that the additional capacity be provided to Program Administrators "if capacity is fully procured in a given utility service area (as is the case in the PG&E service territory)…so that, for each program administrator who wishes to expand their program in that area, approximately 50% of eligible customers in the program administrator's service area can enroll in the program."[20] The PD references adopting the Joint CCAs' proposal but seems to base the increase on whether each Program Administrator individually was close to being fully procured as of October 31, 2023, rather than increasing capacity based on IOU service area as originally proposed by the Joint CCAs, or taking into account the continued growth of the CCA DAC-GT programs.

The Joint CCAs support the PD's ultimate conclusion and calculation methodology, however, the Joint CCAs believe the PD commits a factual error in its interpretation of the record and the Joint CCAs propose the following recommendations to better reflect the record and ensure the increased capacity achieves the goals of Pub. Util. Code Section 769.3 to promote robust participation by low-income customers. The Joint CCAs propose that the PD be revised to increase the DAC-GT capacity cap for all CCA Program Administrators.

As the Joint CCAs have demonstrated in the record, the DAC-GT program has continued to grow as this proceeding has been ongoing.[21] CCA Program Administrators that were not

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18 *Id.*

19 *Id.*

20 Opening Brief of the Joint Community Choice Aggregators and City and County of San Francisco ("Joint CCA Opening Brief") at 25.

21 *See* Opening Comments of the Joint Community Choice Aggregators and City and County of San Francisco on Administrative Law Judge's Ruling Seeking Comments on Aspects of Net Value Benefit Tariff Proposal at 3-5.

granted additional capacity in the PD, such as Ava and CalChoice,[22] are currently negotiating for, or have already procured, power purchase agreements that would fully cover their current DAC-GT program capacity.[23] The PD's definition of "Program Administrators that are close to or fully procured within a particular utility service territory" does not include these Program Administrators. Moreover, the PD's definition does not address recently authorized CCA Program Administrators, such as SDCP, that have not had the opportunity to procure to their allocation at the time of this PD, and therefore would miss out on additional capacity to serve their customers.

Finally, the Joint CCAs suggested the Commission adopt a formal process to transfer unused program capacity between Program Administrators as well as a formal process to allocate additional program capacity to a CCA upon expansion of its service territory.[24] These formal transfer requirements would have ensured that low-income customers in these service territories secure their participation in the DAC-GT program if (i) a Program Administrator has excess capacity that is not being used and/or (ii) the number of eligible customers a CCA serves increases due to the expansion of its service territory.[25]

As no formal transfer process has been included in the PD, and multiple Program Administrators are near to reaching their capacity cap as this decision is being considered, the

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22 California Choice Energy Authority ("CalChoice") supports the joint DAC-GT program of LCE, PRIME, and SJP.

23 Ava Community Energy submitted its Tier 2 Advice Letter requesting Commission approval of its power purchase agreement on February 23, 2024. Cal Choice will likely submit its power purchase agreement to the Commission for approval within the next couple months.

24 *See generally* Joint CCA Opening Brief.

25 For example, Ava Community Energy will soon be expanding to the cities of Stockton and Lathrop in 2025. A large portion of residential customers in the city of Stockton (about 44 percent) are enrolled in the California Alternate Rates for Energy ("CARE") program. Without an increase in the DAC-GT capacity cap for Ava, those customers may lose their discount if they are already enrolled in the DAC-GT program in PG&E's territory, and/or will be ineligible to subscribe for the DAC-GT program in Ava's territory.

Joint CCAs would request that the additional 50 percent increase as calculated in the PD apply to all CCA Program Administrators. This would result in a total increase of 49.637 MW of additional DAC-GT capacity before consolidation with CSGT (an additional 12.321 MW from the originally contemplated 37.316 MW in the PD).[26] This increase would ensure robust participation by low-income customers by providing Program Administrators more opportunity to grow their DAC-GT program.

Additionally, the Joint CCAs understand that the original program rules provided for in Resolution E-4999 with regards to allocation transfers would still apply to the modified DAC-GT program.[27] This provision, in addition to the newly proposed DAC-GT program sunset would prevent ongoing unused DAC-GT program capacity associated with this increase. Altogether, the Joint CCAs believe these revisions better support the record of this proceeding while meeting the goals of AB 2316.

C. The Proposed Decision Should be Clarified to Ensure the Consolidation of the DAC-GT and CSGT Programs Protects CSGT Customers and Projects

While the Joint CCAs have supported the continuation of the CSGT program through this proceeding, the Joint CCAs ultimately understand the PD's reasoning and conclusion to consolidate the DAC-GT and CSGT programs. However, the Joint CCAs request clarification regarding the consolidation of the programs. Specifically, the Joint CCAs request that the PD be revised to clarify (i) that the full CSGT capacity would be transferred to the modified DAC-GT programs, (ii) CSGT projects contracted for as of the transition date under this decision,

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[26] Assumes an additional 0.913 MW for CleanPowerSF, 0.655 MW for CalChoice, 2.863 MW for Ava (formerly EBCE), and 7.89 MW for SDCP).

[27] Resolution E-4999 at 54, Findings and Conclusions 16 ("To provide CCAs flexibility in approaching implementation of their DAC-GT or CSGT programs, it is reasonable to allow CCAs that serve customers that are served by the same IOU to share and/or trade program capacity as described in this Resolution"); *see also* Resolutions E-5102, E-5124, and E-5130.

(regardless of where those contracts are in the Commission review process) will transition into the modified DAC-GT program,[28] (iii) that the DAC-GT project size minimum does not apply to existing CSGT projects or CSGT solicitations issued prior to the implementation of the Final Decision, and (iv) that each identified Community Sponsor associated with CSGT projects will be included in the transition.

First, the PD provides that IOUs and CCAs "shall transfer all remaining un-procured capacity assigned to [the CSGT] tariff to the modified [DAC-GT]."[29] Additionally, in Table 7 of the PD, the Commission provides for the modified DAC-GT total available capacity with the un-procured CSGT capacity included in the calculation.[30] The PD further provides the option for IOUs and CCAs to move legacy CSGT projects to the modified DAC-GT program.[31] To avoid confusion, the Joint CCAs request that the PD be revised to remove language indicating that "un-procured" CSGT capacity may be assigned to the modified DAC-GT program, and instead state that all CSGT capacity may be assigned. This would support the PD's authorization to "allow the transfer of previously enrolled [IOU] or CCA customers to the modified DAC-GT,"[32] ensuring (i) that all current CSGT customers are protected and may maintain their bill discounts, and (ii) there is no confusion with regards to whether the CSGT customers are included in an updated DAC-GT capacity cap.

Second, the Joint CCAs request that the PD be clarified to state that all CSGT projects contracted for as of the mailing date of this decision, regardless of where those contracts are in

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28 As noted above in footnote 23, Ava submitted two CSGT contracts for Commission review in Advice Letter 46-E, and additional contracts may be forthcoming from other CCAs. The goal of this clarification is to confirm that contracts such as and including these will transition to the modified DAC-GT program.

29 Proposed Decision at 167, OP 2.

30 *Id*. at 138-139, Table 7 Modified DAC-GT Capacity Estimate by Program Administrator.

31 *Id*. at 137.

32 *Id*.

the Commission review process, will transition to the modified DAC-GT program. As mentioned above, the PD permits IOUs and CCAs the option to move "legacy" CSGT projects to the modified DAC-GT successor tariff but does not define "legacy" projects. The Joint CCAs request that the language in the PD be revised to reference "contracted CSGT projects and projects that will be under contract after completion of a solicitation that was launched prior to the issuance of a Final Decision" as opposed to "legacy CSGT projects."

Additionally, Decision ("D.") 18-06-027 adopted the DAC-GT program with a minimum project size of 500 kW in order to maintain consistency between the project size of the DAC-GT program and the then existing green tariff shared renewables option.[33] However, the decision did not establish a lower size limit for the CSGT program.[34] The Joint CCAs recommend that the PD be amended to ensure that CSGT projects may transfer to the modified DAC-GT program regardless of project size.

Finally, the PD states that IOUs and CCAs may allow the transfer of "previously enrolled [IOU] or CCA [CSGT] customers to the modified DAC-GT."[35] However, as provided in Resolution E-4999, community sponsors are eligible to subscribe to up to 25 percent of a CSGT project's capacity.[36] The PD should be revised to specifically indicate that, along with contracted CSGT projects and enrolled customers, Program Administrators may also transfer community sponsors that are (1) associated with CSGT projects under contract, or (2) will be under contract after completion of a solicitation that was launched prior to the issuance of a Final Decision. Additionally, a CSGT community sponsor should be eligible to be transferred to the modified

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33 D.18-06-027 at 51.

34 *Id*. at 73 ("Thus (unlike the 500KW limit for the DAC Green Tariff program) we do not set a lower limit for Community Solar Green Tariff projects.")

35 Proposed Decision at 137.

36 Resolution E-4999 at 3.

DAC-GT program if they subscribe to a CSGT project within 90 days of such project's commercial operation date. This proposed modification protects community sponsors that aided in the development of CSGT projects, assisted Program Administrators with marketing, education, and outreach related to community solar projects, and relied upon the CSGT program for energy delivery.

D. The Proposed Decision Should be Modified to Remove the Creation of a Central Marketing Website

The PD requires the development of a central marketing website "including, but not limited to, information on each program and how to apply, procurement opportunities, and statewide program enrollment."[37] The PD errs in concluding that a centralized website is needed to assist in overcoming barriers in customer and project developer awareness of the tariff options.[38] Among other things, a central website with program information already exists on the Commission's website.[39] The current Commission website already includes information on each program and links to each Program Administrator's website which includes instructions on how to apply for the program as well as procurement opportunities. Finally, the website includes a section on the DAC-GT quarterly reports for each Program Administrator which indicate the program enrollment statistics and the amount of capacity each Program Administrator has procured.

Additionally, the Joint CCAs have shown in the record of this proceeding that the need for a central marketing website to support program procurement and customer enrollment is not

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37 Proposed Decision at 129.

38 *Id*. at 172, OP 13 ("The objective of the website is to assist in overcoming barriers in customers and project developer awareness of the tariffs in the portfolio."); *see also Id*. at 129.

39 *See* CPUC's Disadvantaged Communities Green Tariff DAC-GT Program, available at: https://webprod103.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/solar-in-disadvantaged-communities/the-disadvantaged-communities-green-tariff-dac-gt-program.

supported. The original recommendation for a centralized marketing entity was made in the Evergreen Independent Evaluator Report ("Independent Evaluator Report") in order to address a lack of engagement in the programs.[40] The Joint CCAs have established that this recommendation was based on outdated facts.[41] The CCAs have implemented various strategies to increase developer knowledge of, and interest in, the DAC-GT program.[42] There is no support in the record to indicate that a centralized marketing website would improve awareness of the DAC-GT program.

Finally, a centralized marketing website creates challenges associated with established enrollment processes. Many Program Administrators have programs that are currently fully subscribed. As discussed in more detail in Section E below, the CCAs have successfully enrolled customers in the DAC-GT program using both auto- and manual enrollment processes. As such, a website aiming to improve customer awareness of the DAC-GT program is at best redundant, and at worst may cause customer confusion by directing customers to apply for programs that are already at capacity and which may already include a process to add new customers automatically in the event of churn.

E. The Proposed Decision Should be Revised to Remove the Adoption of Auto-Enrollment for the Modified DAC-GT

The PD adopts a proposal for automatic enrollment or auto-enrollment of eligible customers in the modified DAC-GT in order to "address historical enrollment concerns."[43] The PD presumes that auto-enrollment "should improve the current enrollment statistics for low-

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40 Independent Evaluator Report at 42.

41 Exhibit JCCA-02: Prepared Rebuttal Testimony on Behalf of the Joint Community Choice Aggregators and City and County of San Francisco ("Joint CCA Rebuttal Testimony") at 6.

42 *Id*. at 6-7

43 Proposed Decision at 133.

income customers."[44] Therefore, the PD directs CCAs to follow the auto-enrollment practice adopted by the Commission in D.20-07-008 and reiterated in Resolution E-5124.[45] The Joint CCAs believe the PD errs in its conclusion as the record does not support enrollment concerns associated with manual enrollment.

There is not sufficient evidence in the record to support the PD's conclusion that auto-enrollment would address historical enrollment concerns. As the Joint CCAs have demonstrated, CCA Program Administrators have successfully enrolled customers in the DAC-GT programs using a mix of auto- and manual enrollment.[46] While the Joint CCAs recognize that auto-enrollment may remove barriers for some Program Administrators, manual enrollment can, in some instances, enhance customer awareness of the DAC-GT program further incentivizing participation.[47] The Joint CCAs have provided examples of instances where auto-enrollment may be appropriate for some Program Administrators and not for others.[48] The PD notes that PG&E's DAC-GT program is fully subscribed through auto-enrollment.[49] However, there is no analysis provided to connect the conclusion that PG&E's program subscription is due solely to auto-enrollment. An opposing example is CPA, which elected to employ manual enrollment in their DAC-GT program in 2021 and is also fully subscribed.[50] The Joint CCAs request that the PD be revised to remove the requirement for auto-enrollment and reflect the record that ultimately it is the Program Administrators that are best suited to decide whether to use auto-enrollment, manual enrollment, or a combination of both.

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[44] *Id.*

[45] *Id.*

[46] *See* Exhibit JCC-001: Prepared Testimony on Behalf of the Joint Community Choice Aggregators and City and County of San Francisco ("Joint CCA Opening Testimony").

[47] *Id.* at 35.

[48] *Id.*

[49] Proposed Decision at 51.

[50] Exhibit JCC-001: Joint CCA Opening Testimony at 35.

F. The Proposed Decision Should be Revised to Clarify that IOU and CCA Tariffs Need Not be Uniform

The Proposed Decision states that "[IOUs] and participating CCAs shall coordinate before submitting the advice letters *to ensure uniformity*, to the extent possible to ensure that tariff language is uniform across the state."[51] The Joint CCAs are not opposed to coordination with the IOUs to ensure that the program rules and obligations are consistent, however, uniformity should not be the goal. IOUs and CCA program tariff may have differences that are stylistic differences and/or differences specific to their service territories. A requirement that tariff language is uniform across the state is impractical and potentially creates unnecessary issues. For example, requiring uniformity may require changes to the CCA or IOU tariffs beyond the program changes described in a Final Decision and would impinge on the CCAs' ratemaking authority. The Joint CCAs recommend that the PD be revised to request consistency rather than uniformity across the IOU and CCA program tariffs.

G. The Proposed Decision Should be Updated to Provide More Clarity on Timing and Applicability of Existing Program Rules

The Joint CCAs request that the PD be updated to answer outstanding questions and provide more clarity on the transition of program rules and timing of next steps. First, the Joint CCAs request that the PD be revised to clarify that the current DAC-GT program rules will remain in effect and apply to solicitations initiated under the current program rules until the DAC-GT tariffs are updated and approved by the Commission to ensure market certainty. Second, the PD should be revised to clarify when IOUs and CCAs shall submit a Tier 2 Advice Letter updating their program tariffs.

[51] Proposed Decision at 171, OP 9 (*emphasis added*).

First, the PD proposes several changes to the modified DAC-GT program. As the Joint CCAs have demonstrated through this proceeding, the DAC-GT and CSGT programs have been running successfully in conjunction with the issuance of this PD. However, the PD provides for additional workshops and rulings that will result in a subsequent proposed decision. For example, the PD requires the IOUs and CCAs to work together to develop a proposal for updating the DAC-GT cost containment cap, indicating that the IOUs must submit a joint Tier 2 Advice Letter no later than 90 days from the adoption of this decision.[52] Additionally, the PD calls for workshops to discuss website reporting and the automation of data collection.[53] The Joint CCAs request that the PD be revised to clarify that the current DAC-GT program rules, remain in effect until such a time as the DAC-GT tariffs are updated and approved by the Commission, and that Program Administrators may continue implementing their DAC-GT programs in tandem with any ongoing workshops or subsequent ruling. Additionally, the Joint CCAs request that the PD clarify that the current cost containment cap remains in effect, and Program Administrators may continue to procure DAC-GT resources, until such a time as an updated cost containment cap is adopted by the Commission. Many CCA Program Administrators are currently in the middle of solicitations and/or power purchase agreement negotiations. Without these clarifications, there could be a significant delay in improvement to the DAC-GT program.

Additionally, Ordering Paragraph 9 states that *no later than 60 days from the adoption of this decision*, Program Administrators shall submit a Tier 2 Advice Letter updating DAC-GT program tariffs.[54] However, the Proposed Decision also states that *no later than 90 days from the*

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52 *See Id*. at 134.

53 *Id*. at 170, OPs 7-8.

54 *Id*. at 170-171, OP 9.

adoption of the second decision, IOUs and participation CCAs shall submit a Tier 2 Advice Letter updating their existing Green Access Program tariffs.[55] The Joint CCAs request that the PD be revised to conform with Ordering Paragraph 9 and clarify the timing on the submission of the Tier 2 Advice Letter.

Finally, the PD provides that IOUs *and participating CCAs* shall work together to develop a proposal for updating the cost containment cap.[56] However, Ordering Paragraph 4 orders only the IOUs to work together to develop a proposal, without reference to the participating CCAs.[57] The Joint CCAs request that Ordering Paragraph 4 be updated to ensure participating CCAs are included in this process.

III. CONCLUSION

The Joint CCAs thank the Commission for its consideration of the matters set forth in these comments and requests adoption of the recommendations proposed herein.

March 25, 2024

Respectfully Submitted,

/s/ Brittany Iles

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55 *Id*. at 145.
56 *Id*. at 134 (*emphasis added*).
57 *Id*. at 169, OP 4.

Appendix A
Proposed Revisions

Pursuant to Rule 14.3(b) of the Commission's Rule of Practice and Procedure, the Joint CCAs provide this Appendix setting forth proposed changes to the *Proposed Decision Green Access Program Tariffs and Adopting a Community Renewable Energy Program*. The Joint CCAs' proposed revisions appear in underline and strike-through.

Findings of Fact

99. It is efficient to combine the ~~unprocured~~ capacity of the CSGT and DAC-GT, transition customers and community sponsors on the existing CSGT to the modified DAC-GT, allow the enrollment of previously wait-listed customers, and focus on improving future enrollment of low-income customers.

~~106. Adopting the auto-enrollment practice adopted by the Commission in D.20-07-008 for use in the modified DAC-GT is efficient and will improve the current enrollment statistics for low-income customers.~~

114. The following improvements will lead to potential enrollment increases in the modified DAC-GT, thus addressing the Pub. Util. Code Section 769.3 goal of promoting robust participation by low-income customers (1) move legacy CSGT projects to the modified DAC-GT; (2) transfer previously enrolled utility or CCA customers to the modified DAC-GT; and (3) increase the cap of ~~each~~ certain Program Administrators, including all CCA Program Administrators, and Program Administrators that ~~is~~ are close to being fully procured within a particular utility service territory, to allow enrollment of an additional 50 percent of eligible customers.

Conclusions of Law

23. The Commission should consolidate ~~unprocured~~ CSGT capacity into a modified DAC-GT.

~~26. The Commission should adopt the proposal for auto-enrollment in the modified DAC-GT.~~

27. The Commission should direct Utilities and participating CCAs to work together to develop a proposal for updating the cost containment cap.

30. The Commission should adopt the following revisions to improve access to renewable energy: (1) move legacy CSGT projects to the modified DAC-GT; (2) transfer previously enrolled utility or CCA customers to the modified DAC-GT; and (3) increase the capacity cap of ~~each~~ certain DAC-GT Program Administrators, including all CCA Program Administrators, and Program Administrators who ~~is~~ are close to being fully procured within a particular utility service territory, and enroll an additional 50 percent of eligible customers.

Ordering Paragraphs

1. A community renewable energy program is adopted and shall contain the following elements:

> (a) Foundational Tariff – Selection of one of the existing Utility tariffs that are compliant with the federal Public Utility Regulatory Policies Act including, but not limited to, the Renewable Market Adjusting Tariff (ReMAT) and Standard-Offer-Contract. Inclusion of tariffs from participating Community Choice Aggregators (CCA), including newly created or existing tariffs. Developers shall adhere to the previously adopted tariff rules for the selected foundational tariff.
>
> (i) CCAs that intend to participate in this program must notify the Commission within 180 days from the adoption of the second decision in this proceeding in accordance with Pub. Util. Code Section 769.3(b)(2)(B).

2. The Community Solar Green Tariff (CSGT) is discontinued. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (collectively, Utilities) and Community Choice Aggregators (CCAs) shall transfer all ~~remaining un-procured~~ capacity assigned to this tariff to the modified Disadvantaged Communities Green Tariff (DAC-GT). Utilities and CCAs may transition customers and community sponsors currently enrolled in CSGT into the modified DAC-GT~~, unless there is no remaining capacity~~ subject to the combined capacity cap. ~~If capacity is at subscription maximum, Utilities and CCAs are responsible for informing the customer of the loss of their discount.~~ CSGT projects contracted for as of the transition date under this Decision will transition to the modified DAC-GT.

3. The Disadvantaged Communities Green Tariff shall be modified as follows:

> (d) Capacity is increased by an additional ~~37.316~~ 49.637 megawatts of additional capacity.
>
> (e) The capacity cap of ~~each~~ certain Program Administrators, including all CCA Program Administrators, who ~~is~~ are close to being fully procured within a particular utility service territory, is increased to allow the enrollment of an additional 50 percent of eligible customers.
>
> ~~(g) The auto-enrollment process, as adopted in Decision 20-07-008 and modified in Resolution E-5124, shall be implemented.~~

4. Pacific Gas and Electric Company (PG&E)~~, and~~ Southern California Edison Company (SCE), and participating Community Choice Aggregators (CCAs), shall work together to develop a proposal for updating the cost containment cap for the Disadvantaged Communities Green Tariff. No later than 90 days from the adoption of this decision, PG&E and SCE shall submit a Tier 2 Advice Letter proposing a method for updating the cost containment cap.

9. No later than 60 days from the adoption of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) and /or participating Community Choice Aggregators (CCAs) shall each submit a Tier 2 Advice Letter updating their Community Solar Green Tariff according to Ordering Paragraph 2, their Disadvantaged Communities Green Tariff according to Ordering Paragraph 3, and/or their Enhanced Community Renewables and Green Tariff according to Ordering Paragraph 5 above. Utilities and participating CCAs shall coordinate before submitting the advice letters ~~to ensure uniformity,~~ to the extent possible to ensure that tariff language is ~~uniform~~ consistent across the state. The advice letter shall include details on how the tariff(s) will result in incremental new renewable energy being purchased.

~~13. Energy Division is authorized to hire a consultant to develop a statewide website for the Commission's portfolio of renewable energy programs adopted in this decision, subject to budget appropriation. The objective of the website is to assist in overcoming barriers in customers and project developer awareness of the tariffs in the portfolio. Energy Division is authorized to provide early access to a draft version of the website and related content to this service list for informal party and other stakeholder comment to ensure the webpages are clear and complete.~~

APRIL FILINGS

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

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
And Related Matters.	A.22-05-023 A.22-05-024

REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND CITY AND COUNTY OF SAN FRANCISCO ON THE PROPOSED DECISION MODIFYING GREEN ACCESS PROGRAM TARIFFS AND ADOPTING A COMMUNITY RENEWABLE ENERGY PROGRAM

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April 2, 2024

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Review of the Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Tariff Shared Renewables Programs.	A.22-05-022
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REPLY COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS AND CITY AND COUNTY OF SAN FRANCISCO ON THE PROPOSED DECISION MODIFYING GREEN ACCESS PROGRAM TARIFFS AND ADOPTING A COMMUNITY RENEWABLE ENERGY PROGRAM

I. Introduction

Pursuant to Rule 14.3(d) of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Ava Community Energy ("Ava")[1], Clean Power Alliance of Southern California ("CPA"), the City and County of San Francisco, acting by and through its Public Utilities Commission ("CleanPowerSF"), Lancaster Choice Energy ("LCE"), Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority ("PCE"), Pico Rivera Innovative Municipal Energy ("PRIME"), San Diego Community Power ("SDCP"), San Jacinto Power ("SJP"), and San José Clean Energy ("SJCE") (collectively, the "Joint Community Choice Aggregators" or "Joint CCAs") hereby submit these reply comments.

II. The Disadvantaged Communities Green Tariff Cost Containment Cap Should Reflect the Option to Include Paired Battery Storage

The Joint CCAs support the Proposed Decision's ("PD") conclusion that it is reasonable to update the cost containment cap for the modified Disadvantaged Communities Green Tariff

[1] Previously East Bay Community Energy ("EBCE"). Ava filed its Notice of Party Name Change on January 17, 2024.

("DAC-GT") program so that it reflects current market prices and developer costs.[2] However, it is important that the new cap reflect modifications to the DAC-GT program included in the PD, including the voluntary inclusion of storage in DAC-GT solicitations.[3] As such, the Joint CCAs support the Public Advocates Office's ("Cal Advocates") proposal to revise the PD to specify that the cost containment cap proposal must contain an option for projects to include paired battery storage.[4] The Joint CCAs are not proposing a specific methodology for including storage in these comments but rather are emphasizing the importance of ensuring that storage is considered as the methodology for updating the cap is developed. Additionally, the Joint CCAs reiterate that Ordering Paragraph 4 should be revised to ensure that both IOUs and participating CCAs shall work together to develop this proposal. Finally, the Joint CCAs oppose Solar Landscape's proposal that the cost cap be made public, as consideration of this has not previously been raised in the record and a public cost cap would incentivize developers to bid projects at the highest allowable price and unnecessarily inflate program costs.[5]

III. The Eligibility Criteria for the Modified DAC-GT Program Should be Clarified to Include CSGT Community Sponsors and Resolution E-5212

In its opening comments, Pacific Gas and Electric Company ("PG&E") requests that the PD be revised to make it clear that current non-income qualified CSGT customers should not be transitioned to the modified DAC-GT program.[6] PG&E's proposal would also result in community sponsors being excluded from the modified DAC-GT program. Community sponsors

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2 Proposed Decision at 134.

3 *Id*. at 129.

4 Opening Comments of the Public Advocates Office on the Proposed Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program ("Cal Advocates Opening Comments") at 4.

5 Opening Comments of Solar Landscape Origination, LLC on Proposed Decision at 7.

6 Opening Comments of Pacific Gas and Electric Company to the Proposed Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program ("PG&E Opening Comments") at 4.

invested time and resources in the CSGT program to encourage shared solar development in their communities. Removing sponsors from the program upon consolidation unreasonably penalizes them for their participation and risks decreased sponsor trust and participation in future Commission programs. Therefore, the PD should be clear that all CSGT community sponsors may transition into the modified DAC-GT.

Additionally, the Joint CCAs agree with PG&E's request that the PD be revised to clarify that DAC-GT resources may be sited within five miles of any "DAC-GT-eligible community" as defined under Resolution E-5212[7] which expanded DAC-GT customer eligibility.[8] The Joint CCAs agree that there is nothing in the record that would warrant changes to the eligibility criteria as outlined in E-5212.

IV. Any Newly Adopted Community Renewable Energy Program Should be Open to All Customers Including CCA Customers

As noted by the Joint CCAs in opening comments, based on the language in Assembly Bill 2316 and the PD's conclusion that all customers will be eligible to enroll as subscribers in the new Community Renewable Energy program ("CRE"), it is clear that CCAs may participate in the CRE.[9] However, Southern California Edison Company ("SCE") proposes that the final decision "clarify that the utilities should offer developers the option to select either the PURPA Standard Offer Contract or ReMAT as their 'Foundational Tariff'" in implementing the CRE.[10]

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7 *Id*. at 5.

8 Resolution E-5212 at 15 (expanding customer eligibility to (i) all eligible DACs from prior versions of CalEnviroScreen, beginning from the time at which a Program Administrator's DAC-GT implementation advice letter is approved, as well as (ii) all California Indian Country."

9 Opening Comments of the Joint Community Choice Aggregators and City and County of San Francisco on the Proposed Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program ("Joint CCA Opening Comments") at 3.

10 Opening Comments of Southern California Edison Company on the Proposed Decision of Administrative Law Judge Hymes Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program ("SCE Opening Comments") at 3.

SCE's proposal effectively excludes additional tariffs from eligibility as a CRE foundational tariff.[11] The Joint CCAs reject SCE's recommendation as it would unreasonably limit CCAs from participating in the CRE. First, pursuant to Decision 21-12-032, CCAs are ineligible to participate in the ReMAT program. Second, CCAs are not subject to PURPA and therefore do not offer PURPA Standard Offer Contracts. Requiring CCAs to offer investor-owned utility ("IOU") tariffs, instead of tariffs which reflect that specific CCA's costs, would be inappropriate and strongly disincentivize CCA participation. The PD should be clarified to confirm that interested CCAs may create and utilize their own tariffs for any newly adopted community energy program. The CRE should not be limited to only the IOUs' PURPA Standard Offer Contracts or ReMAT tariffs.

V. The Timeline for Modified DAC-GT Advice Letters Should be Adequate and Consistent Across all Program Administrators

The Joint CCAs support PG&E's request that the modifications to DAC-GT program tariffs be due through an Advice Letter 90 days after the Final Decision as opposed to 60 days.[12] The Joint CCAs would also support SCE's proposal for the modified DAC-GT Advice Letter to be due 120 days after issuance of a Final Decision as well as the request for 150 days from the approval of the modified DAC-GT tariff advice letters to facilitate a workshop to discuss the California Distributed Generation Statistics ("DGStats") website reporting.[13] The Joint CCAs believe that both of these proposals will better allow the Program Administrators to update their tariffs according to the PD. The Joint CCAs support a timeline that allows adequate time for necessary modifications and is consistent across the Program Administrators.

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11 *Id.*, Appendix A at 22.

12 PG&E Opening Comments at 4.

13 SCE Opening Comments at 10-11.

VI. Public Utility Code Sec. 769.3(c) Evaluation Criteria Do Not Apply to DAC-GT and CSGT; DAC-GT Meets Public Utility Code Sec. 769.3(b) Standards

The Joint CCAs disagree with Cypress Creek Renewables, LLC's ("Cypress Creek's") implication that the evaluation criteria in Public Utility Code Section 769.3(c) are applicable to the DAC-GT and CSGT programs.[14] Cypress Creek fails to establish that the six criteria in Section 769.3(c) are applicable to DAC-GT through their own statutory interpretation and fails to respond to the analysis previously provided by the Joint CCAs establishing that the DAC-GT and CSGT programs are not subject to these requirements.[15] Accordingly, the Commission should maintain its conclusion from the PD that Section 769.3(c) is not applicable to DAC-GT and CSGT in their final decision in the instant proceeding.[16] Additionally, the Joint CCAs disagree with party comments that assert that the DAC-GT program does not meet the standard of "robust participation by low-income customers" if those comments refer to the metric of Public Utilities Code Section 769.3(b)[17] as the Joint CCAs have already demonstrated robust participation in the program pursuant to Public Utilities Code Section 769.3(b).[18]

VII. Conclusion

The Joint CCAs thank the Commission for its consideration of the matters set forth in these comments.

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14 Comments of Cypress Creek Renewables, LLC on the Proposed Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program at 14.

15 *See* Reply Brief of the Joint Community Choice Aggregators and City and County of San Francisco.

16 Proposed Decision at 25-27.

17 *See* Clean Coalition Opening Comments at 1 ("As written, the PD will not result in a new community renewables program capable of meeting the legislatively mandated requirements in AB 2316…(e.g., robust participation by low-income customer groups.").

18 *See* Exhibit JCC-001: Prepared Testimony on Behalf of the Joint Community Choice Aggregators and City and County of San Francisco ("Joint CCA Opening Testimony").

April 2, 2024

Respectfully Submitted,

/s/ Brittany Iles

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	R.22-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADDRESSING ASSEMBLY BILL 205 REQUIREMENTS FOR ELECTRIC UTILITIES

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April 16, 2024

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page

California Public Utilities Commission Proceedings

California Public Utilities Commission Rules of Practice and Procedure

California Legislation

SUMMARY OF RECOMMENDATIONS

The California Community Choice Association recommends the California Public Utilities Commission adopt the following elements of the proposed *Decision Addressing Assembly Bill 205 Requirements for Electric Utilities* (Proposed Decision):

- Exclusion of the Power Charge Indifference Adjustment and Competition Transition Charge from the Income-Graduated Fixed Charges (IGFC) to comply with Assembly Bill 205;
- Establishment of a Marketing, Education, and Outreach (ME&O) plan development process to ensure the investor-owned utilities (IOUs) incorporate community choice aggregator (CCA) feedback into ME&O plans;
- Establishment of an implementation working group to allow CCA feedback on implementation; and
- Amend the Proposed Decision to direct the IOUs to include IGFC tier data in existing customer data reports to CCAs on a regular basis.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	R.22-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ADDRESSING ASSEMBLY BILL 205 REQUIREMENTS FOR ELECTRIC UTILITIES

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[2] on the proposed *Decision Addressing Assembly Bill 205 Requirements for Electric Utilities*[3] (Proposed Decision), mailed March 27, 2024. This decision authorizes all investor-owned electric utilities to change the structure of residential customer bills in accordance with Assembly Bill (AB) 205, Stats. 2022, ch. 61.[4]

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1 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, 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: cal-cca.org.

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

3 Proposed *Decision Addressing Assembly Bill 205 Requirements for Electric Utilities*, Rulemaking (R.) 22-07-005 (Mar. 27, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M528/K422/528422138.PDF.

4 Assembly Bill No. 205: https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB205.

I. INTRODUCTION

CalCCA appreciates the Commission's thorough discussion of stakeholder evidence presented in Track A of this proceeding and its thoughtful conclusions for implementing the Income-Graduated Fixed Charge (IGFC) required by AB 205. A major tenant of AB 205 is that the IGFC may only collect fixed costs from customers. The Proposed Decision correctly excludes two sets of costs which are not entirely fixed: the Power Charge Indifference Amount (PCIA) and the Competition Transition Charge (CTC). Additionally, the IGFC has understandably already caught public attention and has raised questions from customers as to what it will look like and how customers will be affected. The Proposed Decision rightfully establishes a marketing, education, and outreach (ME&O) planning process with opportunities for stakeholders to provide feedback as well as an implementation working group for resolving any ongoing issues with implementation. To ensure customer experiences remain consistent regardless of whether they are bundled or unbundled customers, the investor-owned utilities (IOUs) should provide IGFC tier data to CCAs on a regular basis. CalCCA recommends the Commission adopt the following elements of the Proposed Decision to ensure implementation of the IGFC:

- Exclusion of the PCIA and CTC from the IGFC to comply with AB 205;
- Establishment of an ME&O plan development process to ensure the IOUs incorporate CCA feedback into ME&O plans;
- Establishment of an implementation working group to allow CCA feedback on implementation; and
- Amend the Proposed Decision to direct the IOUs to include IGFC tier data in existing customer data reports to CCAs on a regular basis.

II. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION'S EXCLUSION OF PCIA AND CTC FROM THE IGFC TO COMPLY WITH AB 205

The Proposed Decision correctly concludes the IGFC should not recover the PCIA nor the CTC. The Proposed Decision determined that the CTC should not be recovered through the

IGFC since statute requires it be recovered volumetrically[5] and that PCIA costs should not be recovered through the IGFC due to the complexity and volatility of the PCIA.[6] This complexity includes the process to split out fixed and variable costs that the PCIA collects. As argued in Opening Briefs, this process would be complex and administratively onerous to perform.[7] Including the costs of either the PCIA or CTC would prove administratively burdensome and violate the intention to collect only fixed costs through the IGFC. CalCCA supports the Proposed Decision's assessment and recommends the Commission adopt the exclusion of the PCIA and CTC from the IGFC.

III. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION'S ME&O PLAN DEVELOPMENT PROCESS TO ENSURE THE IOUS INCORPORATE CCA FEEDBACK INTO ME&O PLANS

The Proposed Decision's ME&O plan development process should be adopted to ensure IOUs incorporate feedback from CCAs regarding implementation of the IGFC. The Proposed Decision establishes a process in which the IOUs develop a consistent set of definitions around the IGFC with Commission staff, host a workshop with parties, and file a Tier 3 advice letter with ME&O plans.[8] This process provides at least two points for CCAs to provide feedback on IOU ME&O plans for the IGFC based on deep CCA knowledge of their customers and

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5 *See* Proposed Decision, at 63 and; *see also* Proposed Decision Conclusion of Law (COL) 21 (excluding CTC from lists of costs in the IGFC).

6 *See* Proposed Decision, at 64; *see also* Proposed Decision COL 21 (excluding PCIA from lists of costs in the IGFC).

7 *See* R.22-07-005, *CalCCA Opening Brief* pursuant to *Assigned Commissioner's Phase 1 Scoping Memo and Ruling, Administrative Law Judge's Ruling Addressing the Track A Procedural Schedule, Opening Briefs Guidance,* and *Exhibits and Email Ruling Clarifying ALJ Ruling on Track A Briefs, Opening Briefs, and Exhibits* (CalCCA Opening Brief) (Oct. 6, 2023), at 4-5 ("While the fixed costs of the PCIA portfolio would theoretically be eligible based on AB 205's requirements for the IGFC, the PCIA portfolio's variable costs would not be eligible. Separating the fixed costs from variable costs that make up the PCIA portfolio would require fundamentally restructuring the PCIA.").

8 *See* Proposed Decision Ordering Paragraph 3 (directing the IOUs to develop consistent messaging, consult with Commission staff, host a workshop with parties, and file a Tier 3 advice letter for ME&O plans).

communities. For example, knowledge from CCAs could provide feedback for improved messaging based on knowledge of communities that speak a primary language other than English. Reaching all communities for education on the IGFC is critical given the fixed charge will affect every customer. CCAs will also provide important checks and balances when it comes to how the new fixed charges are presented. Customers should be able to understand what the IGFC collects, and messaging should not imply different treatment between bundled and unbundled customers. Therefore, the Commission should adopt the Proposed Decision's ME&O plan development process.

IV. THE COMMISSION SHOULD ADOPT THE PROPOSED DECISION'S ESTABLISHMENT OF AN IMPLEMENTATION WORKING GROUP TO ALLOW CCAS TO PROVIDE FEEDBACK ON IMPLEMENTATION AS LESSONS ARE LEARNED

Similar to Section III above, the Commission should adopt the Proposed Decision's establishment of an Implementation Working Group to allow CCAs to provide feedback to IOUs on an ongoing basis. The Proposed Decision establishes an Implementation Working Group, convened and facilitated by the Commission, to present IGFC-related metrics and hear lessons learned from IOUs once per quarter.[9] While the IOUs are charged with implementing the IGFC, CCAs already have received and will continue to receive questions from customers about the IGFC. This means CCAs will act as another entity gathering data on how IGFC implementation occurs, what may be confusing to customers about the IGFC, and any issues customers identify. This information will be valuable to the IOUs and the Commission when the Implementation Working Group meets on a quarterly basis. For this reason, the Commission should adopt the

[9] *See* Proposed Decision COL 34, 35, and 36 (outlining implementation working group scope and how often the implementation working group will convene).

Proposed Decision's Implementation Working Group to provide a consistent place for CCA feedback on IGFC implementation.

V. THE COMMISSION SHOULD AMEND THE PROPOSED DECISION TO DIRECT THE IOUS TO INCLUDE IGFC INCOME TIER DATA IN EXISTING CUSTOMER REPORTS PROVIDED TO CCAS TO ENHANCE CUSTOMER SERVICE

Related to the IGFC's ongoing implementation, the Proposed Decision should direct the IOUs to augment weekly customer database updates and billing transactions to include customer IGFC income tier data. CalCCA argued this point in its Opening Brief as part of a set of recommendations to enhance customer experience and messaging related to the IGFC.[10] In the same theme as Sections III and IV above, CCAs are and will continue to be a touchpoint for a significant portion of customers, even though the IGFC will reside on the IOU side of the bill. CCAs can currently determine what tier California Alternative Rate for Energy (CARE) and Family Electric Rate Assistance (FERA) program customers will be in because customer participation in CARE/FERA is included in weekly customer reports to which CCAs have access. However, these reports would not include the customers who IOUs will sort into the middle tier through their participation in an affordable housing program that requires an income lower than 80 percent area median income. If the IOUs added this information, or a flag indicating which tier each customer is assigned, to existing CCA customer reports, CCAs could provide an enhanced and more consistent customer experience to all customers, regardless of the reason they are sorted into a specific tier. Therefore, the Commission should amend the Proposed Decision to direct the IOUs to include IGFC income tier information in existing database updates as recommended in Appendix A.

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[10] *See* CalCCA Opening Brief, at 9-10 (providing recommendations to ensure consistent IGFC messaging to bundled and unbundled customers).

VI. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and requests adoption of the recommendations proposed herein. For all the foregoing reasons, the Commission should modify the proposed decision as provided in Appendix A.

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

April 16, 2024

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION ADDRESSING ASSEMBLY BILL 205
REQUIREMENTS FOR ELECTRIC UTILITIES

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

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Proposed text additions show as <u>**bold and underlined**</u>

FINDINGS OF FACT

None.

CONCLUSIONS OF LAW

<u>**74. It is reasonable for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to include income-graduated fixed charge tier information to CCAs through existing database updates and billing transactions.**</u>

ORDERING PARAGRAPHS

None.

New Order:

<u>**16. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each include income-graduated fixed charge tier information for customers in existing customer data reporting processes.**</u>

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING ON DISCONNECTION CAPS AND PAST-DUE PAYMENT ALLOCATION

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April 19, 2024

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS

The California Public Utilities Commission (Commission) should make the proportional allocation of past due payments between investor-owned utilities (IOUs) and community choice aggregators (CCAs) permanent for the following reasons:

- CCAs are in the public interest and should not be required to bear a disproportionate amount of financial risk for unpaid customer bills;
- The California Legislature's and Commission's preference for the proportional allocation of revenue to IOUs and CCAs in analogous situations supports the proportional allocation of past due bill payments to IOUs and CCAs; and
- The proportional allocation method will allow customers to remain with the CCA (rather than being returned to the IOU for nonpayment), allowing customers to benefit from CCA initiatives, potentially lower CCA rates, and local outreach assisting struggling customers.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING ON DISCONNECTION CAPS AND PAST-DUE PAYMENT ALLOCATION

California Community Choice Association[1] (CalCCA) submits these comments pursuant to the *Administrative Law Judge's Ruling on Disconnection Caps and Past-Due Payment Allocation*[2] (Ruling), dated March 22, 2024. CalCCA takes no position on the disconnection caps. The comments below exclusively address the allocation by investor-owned utilities (IOUs) of payments of past-due unbundled customer bills between themselves and community choice aggregators (CCAs). For the reasons set forth below, the California Public Utilities Commission (Commission) should make permanent the proportional allocation of past due payments between IOUs and CCAs.

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, 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 *Administrative Law Judge's Ruling on Disconnection Caps and Past-Due Payment Allocation*, R18-07-005 (Mar. 22, 2024).

I. INTRODUCTION

CalCCA appreciates the opportunity afforded by the Ruling to address whether to permanently discontinue the "Waterfall" method. The Waterfall is the IOU standard practice of crediting customer partial payments on delinquent unbundled customer accounts first to the IOU portion of the bill until the customer account is no longer subject to disconnection for delinquency, and only then to the CCA bill portion. The Waterfall is not required by statute or Commission directive, but is embedded in the Commission-approved IOU tariffs.[3] The Waterfall was suspended multiple times during the Covid pandemic due to the disproportionate and inequitable financial risk it placed on CCAs as compared to IOUs.[4] Instead, the Commission ordered the IOUs to proportionately allocate the past due payments among the IOUs and CCAs, most recently in Decision (D.) 21-11-014 extending the Waterfall suspension through September, 2024.[5]

The Commission's findings supporting suspending the Waterfall in D.21-11-014 apply indefinitely, and support permanently authorizing the proportional allocation method. Significantly, the Commission found in D.21-11-014 that CCAs benefit customers as a whole, are in the public interest, and should not be placed at disproportionate financial risk by the

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3 *See* Pacific Gas and Electric Company (PG&E) Electric Rule 23.R.2, 23.R.3; Southern California Edison Company (SCE) Rule 23.R.2; San Diego Gas and Electric Company (SDG&E) Rule 27.R.2; *see also* D.21-11-014, *Decision Directing Allocation of Payment on Past-Due Bills Between Investor-Owned Utilities and Community Choice Aggregators,* R.21-02-014 (Nov. 18, 2021), at 9 ("[t]he electric utility standard practice of prioritization of payments first to utility charges and secondly to non-utility charges *is not legislatively required"*).

4 *See* Resolution M-4842, extended in M-4849; *see also* PG&E Advice Letters 4244-G-B/5816-E-B, 4388-G/6092-E (approved by Energy Division and suspending until July 1, 2021, PG&E's Waterfall method); *see also* SCE Advice Letter AL 2330G/4205-E (approved by Energy Division and implementing SCE's "Zig Zag" proportional allocation method); *see also* SDG&E Advice Letter 2961-G/3716-E (approved by Energy Division and suspending until July 1, 2021 SDG&E's Waterfall method); *see also* D.21-06-036, *Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment in Long Term Payment Plans,* R.21-02-014 (June 24, 2021) (extending Waterfall suspension to September 30, 2021).

5 D.21-11-014, Ordering Paragraph (O¶) 1, at 17.

Waterfall.[6] Requiring CCAs to bear the brunt of delinquent accounts while the IOUs reap the benefits of 100 percent of past due payments is an inequitable result that defies logic. The Commission should permanently require that IOUs and CCAs receive their proportional share of any past due payments for services they have provided, for the following reasons:

- CCAs are in the public interest and should not be required to bear a disproportionate amount of financial risk for unpaid customer bills;
- The California Legislature's and Commission's preference for proportional allocations of revenue to IOUs and CCAs in analogous situations supports the proportional allocation of past due bill payments to IOUs and CCAs; and
- The proportional allocation method will allow customers to remain with the CCA (rather than being returned to the IOU for nonpayment), allowing customers to benefit from CCA initiatives, potentially lower CCA rates, and local outreach assisting struggling customers.

II. BACKGROUND

The Waterfall was suspended several times during the Covid pandemic, initially up to July 1, 2021, through Advice Letters filed by the IOUs.[7] CalCCA, on behalf of its CCA members, advocated that the Waterfall be suspended given the detrimental financial impact on CCAs, especially as customer arrearages rose.[8] The suspensions accompanied many customer disconnection protection and arrearage assistance programs initiated during the pandemic. The Commission further extended the Waterfall suspensions in D.21-06-036 through September 30, 2021, slating the "permanent determination" of the Waterfall issue for Phase II of the proceeding.[9] In Phase II, the Commission extended the Waterfall suspension for three additional

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6 *Id.,* Finding of Fact (FOF) 8-9, at 16.

7 *See supra,* n. 4.

8 *See* R.21-02-014, *California Community Choice Association Comments on Order Instituting Rulemaking* (March 3, 2021), at 8-10; *California Community Choice Association Opening Brief* (April 23, 2021), at 3-4; R.21-02-014, *Comments of the California Community Choice Association on the Proposed Decision* (June 14, 2021), at 1-8; R.21-02-014, *Comments of California Community Choice Association on the Proposed Decision Directing Allocation of Payment on Past-Due Bills Between Investor-Owned Utilities and Community Choice Aggregators* (Nov. 4, 2021).

9 D.21-06-036, OP 10, at 32-33.

years in D.21-11-014, to September 30, 2024.[10] The Commission made the following specific findings supporting its Waterfall suspensions:

(1) Given that CCAs are in the public interest, shifting the risk of nonpayment from a customer to the CCA, who continues to serve that customer without collecting revenue and therefore placing that CCA in financial risk, is not in the interest of customers as a whole;

(2) Nothing in the Public Utilities Code, including section 779.2 prohibiting disconnecting residential service for indebtedness owed to an entity other than the electrical corporation, requires prioritizing partial past due payments towards IOUs;

(3) The Waterfall cannot be characterized as a uniform disconnection protection because it is a protection that can only be accessed unevenly by customers that have a CCA serving their community; and

(4) In light of relevant, analogous legislative provisions requiring proportional allocation of relief during the pandemic, proportional allocation should continue on the same timeline as the Covid long-term payment plans (i.e., through September, 2024).[11]

As set forth below, the Commission's justifications in D.21-11-014 for extending the suspension of the Waterfall: (1) continue to apply, (2) will apply indefinitely, and (3) support the proportional allocation method being made permanent.

III. THE PROPORTIONAL ALLOCATION METHOD SHOULD BE MADE PERMANENT

The logic and equity behind the Commission's Waterfall suspension throughout the pandemic and through September 2024 in D.21-11-014 will apply indefinitely. Unfortunately, customer arrearages have continued to increase over the past several years, but the inequitable result to CCAs and the public interest of the Waterfall will exist regardless of the arrearage magnitude. For the following reasons, the Commission should make the proportional allocation of past due payments to IOUs and CCAs permanent: (1) CCAs are in the public interest and

[10] D.21-11-014, at 9-10, OP 1, at 17.
[11] *Id.* at 9-10.

should not be required to bear a disproportionate amount of financial risk of unpaid customer bills; (2) the California Legislature's and Commission's preference for proportional allocation of revenue to IOUs and CCAs in analogous situations supports the proportional allocation of past due bill payments to IOUs and CCAs; and (3) the proportional allocation method will prevent or defer CCA customers being returned to the IOU, allowing customers to benefit from CCA initiatives, lower CCA rates, and local outreach assisting struggling customers and potentially preventing disconnection.

A. CCAs are in the Public Interest and Should Not be Required to Bear a Disproportionate Amount of Financial Risk from Unpaid Bills

As noted by the Commission in D.21-11-014, there is no basis in statute, the public interest, or in equity for CCAs to bear a disproportionate amount of financial risk from unpaid bills.[12] The Commission recognized the statutory origin and value of CCAs in D.21-11-014, finding that "CCAs are in the public interest, in that CCAs allow for a publicly-managed alternative to private utility procurement of resources."[13] In addition, the Commission recognized that the Legislature enabled CCAs by enacting Assembly Bill (AB) 117,[14] adding Section 366.2 to the Public Utilities Code, stating that "[c]ustomers **shall** be entitled to aggregate their electric loads as members of their local community with [CCAs]."[15] IOUs are required to continue providing the billing, collection, and customer service functions to CCA customers

12 *Id.,* at 9-10, COL 2-3, at 16 (finding that the Waterfall "is not legislatively required" and rejecting the IOUs' argument that Public Utilities Code section 799.2 supports the Waterfall, stating that section 799.2 only prohibits disconnection for indebtedness owed to an entity other than the utility, and: (1) "does not require utilities to apply payments on outstanding residential utility bills first to utility charges before non-utility charges," and (2) "does not prohibit utilities from allocating payments on outstanding residential utility bills proportionally between utility and non-utility charges").

13 *Id.*, at 11.

14 Stats. 2002, Ch. 838.

15 *Id.,* at 4-5, COL 1, at 16 (citing Public Utilities Code § 366.2(a)(1)) (emphasis added).

(who are still provided transmission and distribution services by the IOU).[16] However, as noted in D.21-11-014, no statute directs the IOUs to pay themselves first when a customer partially pays a past due bill.[17]

The Commission finds in D.21-11-014 that "[f]inancially sound CCAs benefit customers as a whole,"[18] rather than benefitting just the interest of one customer:

> [w]hile it is correct that prioritizing any payments toward utility charges is better for the individual customer, shifting the risk onto the CCA is not in the interest of customers **<u>as a whole</u>** . . . Resources have been devoted to the establishment, integration, and growth of CCAs within the IOU service territories.[19]

Diverting all payments to the IOU of past due amounts through the Waterfall places a CCA in an inequitable and financially precarious position. The Commission should make permanent the equitable solution of proportional allocation of past due payments of utility bills, while relying on other disconnection protections that don't financially harm the entities providing services to customers.

B. The California Legislature and Commission Have Demonstrated a Preference for Proportional Distribution of Revenue Between IOUs and CCAs in Other Contexts

In addition to the extensions of the Waterfall during the pandemic, the California Legislature and Commission have demonstrated a preference for proportional distribution of revenue amongst IOUs and CCAs in analogous contexts to the allocation of past due bill payments. Notable examples of such proportional distribution include:

- AB 135 adding Section 9 to Government Code Section 16429.5(g), requiring: (1) that IOUs use "existing **<u>proportional payment processes</u>** adopted by the [Commission] in response to the COVID-19 pandemic to allocate any partial payment made by customers to the utility and other load serving entities in proportion to their respective

16 Public Utilities Code § 366.2(c)(9).
17 *Id.,* at 9.
18 *Id.*, FOF 9, at 16.
19 *Id.*, at 11-12 (emphasis added).

shares of the outstanding customers charges"; and (2) that funding received through [the California Arrearage Payment Program (CAPP)] against customer charges owing the utility and other load serving entities (including CCAs) be credited **in proportion to** their respective shares of the customer arrearages.[20]

- In addition, the Commission approved a plan for remittances to CCAs with customers enrolled in the Arrearage Management Plan (AMP) for costs of forgiving generation-related arrearages associated with the unbundled customers to be on a **proportional basis**.[21]
- Furthermore, in the Percentage of Income Payment Plan pilot, the Commission requires the IOUs to "remit costs recovered and attributable to CCA customers **proportionally** to the generation costs for customers of the CCA."[22]

Indeed, the proportional allocation of revenue to the entity that earned that revenue is a logical approach chosen by the Legislature and Commission on several occasions and demonstrates a preference toward such proportional allocation.

C. The Proportional Allocation of Past Due Payments Will Defer CCA Customers Being Reverted Back to the IOUs for Nonpayment and Allow Customers to Benefit from CCA Initiatives, Rates, and Outreach Preventing Disconnections

In partnership with the Commission and IOUs, CCAs are working to prevent disconnections and assist customers struggling to pay their bills. Proportional allocation of past due payments will prevent or defer customers being returned to the IOU for nonpayment, allowing customers to benefit from CCA initiatives, rates, and CCA community outreach that can lower customer arrearages and prevent disconnections. Examples of such CCA initiatives include:

- ✓ San Jose Clean Energy (SJCE) established an Emergency Bill Relief pilot program in the first quarter of 2024 that offers up to $1,600 to customers at risk of disconnection. For most participating customers, this level of support is expected to eliminate all

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20 *Id.*, at 5 (citing Government Code Section 16429.5) (emphasis added).

21 Resolution E-5114, *Approval of Arrearage Management Plans for Large Investor-Owned Electric and Gas Utilities,* December 17, 2020.

22 D.21-10-012, *Decision Authorizing Percentage of Income Payment Plan Pilot Programs,* R.18-07-005 (Oct. 7, 2021), at 32 (emphasis added).

overdue balances owed to SJCE and Pacific Gas and Electric Company (PG&E) and temporarily avert disconnections;

- ✓ Peninsula Clean Energy (PCE) provided a $300 bill credit to approximately 5,800 CARE and FERA customers in December, 2023; and
- ✓ MCE continues to work closely with its customers to ensure successful AMP completion – in 2022, MCE's success rate for customer AMP completion was 34 percent, compared to PG&E's success rate of 21 percent.[23]

In addition, many CCA rates are lower than their IOU counterparts, providing CCA customers with lower bills and an increased chance of staying current. For example:

- ✓ Sonoma Clean Power currently saves customers between five to seven percent on their total electric bill;
- ✓ PCE recently announced it will freeze its rates at 2023 levels in response to the announcement of a 15 percent rate increase from PG&E, allowing customers to save between 10-15 percent on their electric generation charges. Since its inception in 2016, PCE has generally offered its customers a discount of at least five percent below PG&E's baseline electric generation rate;
- ✓ SJCE customers currently save above eight percent on electricity compared to PG&E. SJCE has expanded eligibility for its SJ Cares program, which offers an additional 10 percent discount for low-income customers for a total discount of 18 percent; and
- ✓ San Diego Community Power (SDCP) recently approved new rates that will result in customers seeing an average decrease of 17.7 percent in their electricity generation costs compared to their rates in 2023. SDCP had previously approved electricity rates for 2023 that were three percent less than San Diego Gas & Electric's rates.

Finally, the local community focus of CCAs allows them to gauge best strategies in their communities for higher customer participation rates in programs assisting struggling customers. Alongside the Commission and IOUs, CCA initiatives, rates, and outreach can contribute to the prevention of increasing arrearages and potential disconnections.

[23] *See* California Public Utilities Commission, *Report on Residential and Household Utility Service Disconnections Pursuant to Public Utilities Code Section 910.5* (April, 2023), at 12-13.

IV. CALCCA'S RESPONSES TO THE QUESTIONS FOUND IN THE RULING

1. Would extending the use of the proportional allocation method significantly increase the risk of energy disconnections for customers in arrears? Please explain why or why not.

CalCCA does not have access to data to respond to the question of whether extending the use of the proportional allocation method will "significantly" increase the risk of energy disconnections for customers in arrears. The answer to this question will hinge on many factors, including the dollar and time threshold for disconnection set by the IOUs. Regardless and as discussed above, the Waterfall method is an inequitable practice that is not in the public interest, places CCAs at financial risk, and should be permanently discontinued. In addition, CCAs have initiatives, rates, and outreach practices unique to their organizations that can assist customers in preventing increased delinquencies and potential disconnections.

2. Should the proportional allocation method be extended beyond the end of September 2024?

a. If so, should it be extended through October 1, 2026, the period equivalent to the duration of the extended AMP program and 24-month payment plans? Or should the Commission make the proportional allocation method permanent?

The proportional allocation method should be made permanent, and should not be tied to the extended AMP program and 24-month payment plans. The reasoning for replacing the Waterfall with the proportional allocation method applies regardless of whether there is one customer or one million customers in arrears. Payments for past due bills owed to more than one entity (here the IOUs and CCAs) should be allocated to such entities in proportion to the services provided by those entities.

b. If so, should the proportional allocation scheme apply to all past-due payments? If not, which types of past-due payments should be subject to the proportion allocation method?

Yes, the proportional allocation method should apply to all past-due payments.

V. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests that the Commission make permanent the proportional allocation of payments of past-due bills between CCAs and IOUs.

Respectfully submitted,

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CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

April 19, 2024

California Community Choice Association

SUBMITTED 04/23/2024, 12:25 PM

Contact

Shawn-Dai Linderman (shawndai@cal-cca.org)

1. **Please provide your organization's comments on Reliability-driven Projects Recommended for Approval.**

   See response in Section 4.

2. **Please provide your organization's comments on Frequency Response.**

   CalCCA has no comments at this time.

3. **Please provide your organization's comments on Maximum Import Capability Expansion Requests.**

   CalCCA has no comments at this time.

4. **Please provide your organization's comments on Policy-driven Projects Recommended for Approval.**

   <u>Introduction</u>

   The California Community Choice Association (CalCCA) appreciates the California Independent System Operator (CAISO) staff's significant efforts to develop the 2023-2024 Draft Transmission Plan (the Plan). The Plan makes good progress in advancing transmission projects needed for grid reliability and needed to support 85 gigawatts of the new clean generation to meet Senate Bill 100 goals. The plan identifies 26 transmission projects, totaling an estimated cost of $6.1 billion. Nineteen of the projects are reliability-driven and seven are policy-driven. Six of the seven policy--driven projects identified in the plan are driven by the offshore wind (OSW) generation mapped in the Humbolt call area. The cost estimate of these six projects is $3.1-$4.5 billion, a significant portion of the $6.1 billion total estimated costs of the plan. CalCCA supports the adoption of the reliability-driven projects identified in the Plan. For the policy-driven projects, CalCCA recommends the approval process outlined below intended to ensure transmission planning takes into account upcoming regulatory steps likely to inform the pace of OSW development in the state.

Proposed Approval Process for Policy-Driven Projects

Given the significant cost associated with the policy-driven projects identified in the plan and the fact that OSW generation development across the country is still in its infancy, the CAISO should develop a two-step approval process that provides additional time for forthcoming regulatory steps to inform the pace of OSW development in the state. Pursuant to Assembly Bill (AB) 1373, the California Public Utilities Commission (CPUC) must determine if there is a need for the California Department of Water Resources (CDWR) to procure eligible energy resources, including OSW, by September 1, 2024. The direction provided by the CPUC in response to the requirements of AB 1373 will likely inform the need for OSW and at least some of the anticipated procurement steps necessary to meet such a need. The CAISO should wait to request the CAISO Board of Governors' approval of certain policy-driven projects until after September 1, 2024, to allow for additional time to take into account the direction provided by the CPUC in response to its AB 1373 requirements. The CAISO should determine which projects to approve in May versus September as follows:

- Request Board of Governors' approval in May if a project is:
    - Reliability-driven; or
    - Policy-driven, identified in the plan for its ability to support the interconnection and transmission of OSW, and would have been found to provide benefits absent the inclusion of OSW in the portfolio (e.g., the interconnection of alternative clean generation downstream such as the 230 kilovolt (kV) mitigations in the PG&E North of Greater Bay Area).
- Request Board of Governors' approval in September (or later in 2024 if needed) if a project is:
    - Policy-driven, *only* identified in the plan for its ability to support the interconnection and transmission of OSW and does not meet other policy-driven needs absent the inclusion of OSW in the portfolio.

Some policy-driven projects identified in the plan are driven by OSW but offer additional benefits of allowing for the interconnection of other non-OSW clean energy projects (the 230 kV mitigations in the PG&E North of Greater Bay Area). Other policy-driven projects may not provide benefits to the system absent OSW (the 500 kV infrastructure). The approach outlined above will provide the CAISO with the flexibility needed to ensure that, in the event OSW does not get developed as quickly as anticipated or shifts to a different area, transmission investments will not be stranded and will serve the purpose of integrating different sets of clean resources to the grid. Such a "least regrets" approach is prudent to support customer affordability while also developing the transmission infrastructure needed to support the interconnection of new clean generation.

5. Please provide your organization's comments on the Economic Assessment.

CalCCA has no comments at this time.

6. Please provide your organization's additional comments on the Draft 2023-2024 Transmission Plan April 9, 2024 stakeholder call discussion.

CalCCA has no comments at this time.