NOVEMBER FILINGS

**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 TRACK B WORKING GROUP REPORT**

Evelyn Kahl,
General Counsel and Director of Policy
Leanne Bober,
Senior Counsel

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94520
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

November 13, 2023

TABLE OF CONTENTS

Table of Contents continued

SUMMARY OF RECOMMENDATIONS

- The California Public Utilities Commission (Commission) should continue to collect and assess data to inform design of real-time pricing (RTP) rates;
- The Commission should continue to facilitate data sharing and collection between investor-owned utilities (IOUs) and community choice aggregators (CCAs) for successful implementation of RTP rates;
- Load-serving entities (LSEs) should pursue time-of-use and critical peak pricing rates in parallel to the development of RTP rates to maximize near-term load shifting impacts; and
- The Commission and stakeholders should continue to define Environmental and Social Justice goals within RTP rate design;
- Working Group 2's recommendation to utilize the California Energy Commission's (CEC) Market Informed Demand Automation Server system as a price portal, with necessary upgrades as determined by the Commission and the CEC, should be adopted;
- Energy Division's price machine proposal should be adopted;
- IOUs should be required to provide CCAs access to customer usage data, including:
    - Requiring Pacific Gas and Electric Company to provide billing quality usage data to CCAs at hourly or sub-hourly intervals; and
    - Requiring all IOUs to provide non-billing quality hourly customer interval usage data for CCA load forecasting and offering dynamic pricing to unbundled customers;
- In the event dual enrollment between demand response (DR) programs and demand flexible rates is prohibited, the Commission should require IOUs to provide customer enrollment data in DR programs;
- In the context of dynamic pricing, the Commission should ensure equivalent bill presentation between bundled and unbundled customers;
- The Commission must address the complexities regarding customer rate change requests in the context of RTP;
- The IOUs' request for the establishment of a two-way balancing account for the development of systems and processes should be rejected; and
- All LSEs should be able to recover shared categories of costs for the development of systems and processes through the same rate mechanism.

**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 TRACK B WORKING GROUP REPORT**

California Community Choice Association[1] (CalCCA) submits these comments on the *California Public Utilities Commission Demand Flexibility OIR Track B Working Group Report*[2] (Report), dated October 11, 2023, and filed in response to the *Assigned Commissioner's Phase 1 Scoping Memo and Ruling*[3] (Scoping Memo)*,* dated November 2, 2022, and *Email Ruling Modifying Deadlines for Working Group Proposal and Comments,*[4] dated September 29, 2023.

I. INTRODUCTION

Among the objectives of the California Public Utilities Commission's (Commission) Order Instituting Rulemaking (OIR) to establish demand flexibility policies and modify electric

---

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 Rulemaking (R.) 22-07-005, *Track B Working Group Report and Notice of Availability, Attachment A* (Oct. 11, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K541/520541672.PDF.

3 R.22-07-005, *Assigned Commissioner's Phase 1 Scoping Memo and Ruling* (Nov. 2, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M498/K072/498072273.PDF.

4 R.22-07-005, *Email Ruling Modifying Deadlines for Working Group Proposal and Comments* (Sept. 29, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K520/520520661.PDF.

rates is to enable participation in demand flexibility by both bundled customers (i.e., customers of investor-owned utilities (IOUs)) and unbundled customers.[5] Track B of the Demand Flexibility proceeding is considering the adoption of dynamic pricing rates for the IOUs, to support the January 2025, IOU applications to offer marginal cost dynamic rates to each customer class as required by the California Energy Commission's (CEC) Load Management Standards (LMS).[6] Large community choice aggregators (CCA) will have the option to adopt the dynamic price rate design required by the Commission for the IOUs, develop their own dynamic rates, or offer load shifting programs to customers by 2027 pursuant to the LMS requirements.[7] In addition, CCAs are committed to the overall demand flexibility and demand response policies identified by the Commission in the OIR.[8]

As part of Track B, the Commission ordered the formation of Working Groups to address two categories of issues: (1) principles for dynamic pricing rate design, including design principles to enable all load-serving entities (LSEs) to participate in demand flexibility (Working Group 1 (WG 1)); and (2) systems and processes needed for access to dynamic prices and responding to dynamic price signals by both bundled and unbundled customers (Working Group 2 (WG 2)).[9] After many months of meetings, the Report containing the findings of both Working

---

5 R.22-07-005, *Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates* (July 22, 2022) (DFOIR), at 1: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K285/496285639.PDF.

6 Title 20, Art. 5, §§ 1621-1623.1 (2023).

7 *See* LMS § 1623.1(b).

8 DFOIR, at 1 (stating that "the Commission will establish demand flexibility policies and modify electric rates to advance the following objectives: (a) enhance the reliability of California's electric system; make electric bills more affordable and equitable; (c) reduce the curtailment of renewable energy and greenhouse gas emissions associated with meeting the state's future system load; (d) enable widespread electrification of buildings and transportation to meet the state's climate goals; (e) reduce long-term system costs through more efficient pricing of electricity; and (f) enable participation in demand flexibility by both bundled and unbundled customers").

9 Scoping Memo, at 4.

Groups was filed with the Commission on October 11, 2022.[10] CalCCA was actively involved in both Working Groups, and provided input for the Report. The following provides CalCCA's recommendations as the Commission considers the Report:

- The Commission should continue to collect and assess data to inform design of real time pricing (RTP) rates;
- The Commission should continue to facilitate data sharing and collection between IOUs and CCAs for successful implementation of RTP rates;
- LSEs should pursue time-of-use (TOU) and critical peak pricing (CPP) rates in parallel to the development of RTP rates to maximize near-term load shifting impacts; and
- The Commission and stakeholders should continue to define Environmental and Social Justice (ESJ) goals within RTP rate design;
- WG 2's recommendation to utilize the CEC's Market Informed Demand Automation Server (MIDAS) system as a price portal, with necessary upgrades as determined by the Commission and the CEC, should be adopted;
- Energy Division's (ED's) price machine proposal should be adopted;
- IOUs should be required to provide CCAs access to customer usage data, including:
    - Requiring Pacific Gas and Electric Company (PG&E) to provide billing quality usage data to CCAs at hourly or sub-hourly intervals; and
    - Requiring all IOUs to provide non-billing quality hourly customer interval usage data for CCA load forecasting and offering dynamic pricing to unbundled customers;
- In the event dual enrollment between demand response (DR) programs and demand flexible rates is prohibited, the Commission should require IOUs to provide customer enrollment data in DR programs;
- In the context of dynamic pricing, the Commission should ensure equivalent bill presentation between bundled and unbundled customers;
- The Commission must address the complexities regarding customer rate change requests in the context of real time pricing;
- The IOUs' request for the establishment of a two-way balancing account for the development of systems and processes should be rejected; and

---

[10] *See infra,* n. 2.

- All LSEs should be able to recover shared categories of costs for the development of systems and processes through the same rate mechanism.

II. BACKGROUND

A. Working Group 1

The Commission established Track B, WG 1 to develop guidance for demand flexibility rate design. Though the guidelines developed in WG 1 will ultimately inform the IOU LMS applications for implementing RTP rates, Question 3.e. of the Scoping Memo asks, "[h]ow should demand flexibility rates be designed to enable <u>all [LSEs]</u> to have the option to participate?"[11] CalCCA participated in WG 1 to provide CCA perspectives as they relate to Question 3.e. and other aspects of dynamic rate design. On July 7, 2023, CalCCA and CCA staff presented to WG 1 the CCA perspective on the flexibility needed to enable CCA participation in dynamic pricing. In these comments, CalCCA provides a summary of its positions on the WG 1 proposals and responds to comments from other parties included in the Report.

B. Working Group 2

Track B, WG 2 addressed the following general question with respect to the <u>systems and processes</u> necessary to enable dynamic pricing (i.e., RTP):[12]

> How should the Commission ensure access to dynamic electricity prices by bundled and unbundled customers, devices, distributed energy resources, and third-party service providers? What systems and processes should the Commission authorize for access to prices and responding to price signals?[13]

Subsection 4.b. further defines the question with respect to entities serving unbundled customers such as CCAs:

---

11 Scoping Memo, at 4 (emphasis added).

12 The term "dynamic pricing" is used herein interchangeably with "RTP."

13 Scoping Memo, at 5.

> What systems and processes should the Commission authorize to enable load serving entities to offer unbundled customers the option to take service on dynamic electricity prices?

During the WG 2 process, CalCCA presented the barriers known at this time for CCAs to offer dynamic pricing, and the CalCCA proposals to overcome the barriers. In addition to the WG 2 meetings during which these barriers were discussed, several additional meetings were held between the CCAs, ED staff, and the IOUs regarding the identified barriers and potential solutions.[14]

III. CALCCA COMMENTS ON WORKING GROUP 1 PROPOSALS

The Commission tasked WG 1 in this proceeding with proposing a set of guidelines for all demand flexibility rate design applications to be filed by the IOUs. Three sets of parties submitted proposals for WG 1: ED staff; PG&E, Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E) (together referred to as the Joint IOUs), and the Microgrid Resources Coalition (MRC).[15] CalCCA first summarizes its positions on these WG 1 proposals and the six WG 1 Scoping Memo questions and then discusses the following topics in response to WG 1 party comments included in the Report: (1) data collection and assessment to inform RTP rate design; (2) data sharing between IOUs and CCAs for implementation of RTP rates for all customers; (3) the value of LSEs pursuing TOU and CPP rates in parallel to developing RTP rates; and (4) the need to define and incorporate ESJ goals through the development of RTP rates.

---

14 The CCAs and IOUs discussed the barriers in several WG 2 meetings, including meetings on March 24, 2023, and June 30, 2023. The CCAs also had meetings with PG&E and ED on April 20, 2023, May 11, 2023, and July 18, 2023. A meeting between the CCAs, ED, and SCE was held on April 18, 2023. A meeting between the CCAs, ED, and SDG&E was held on May 4, 2023.

15 *See* Report, at 4.

A. Summary of CalCCA Positions on WG 1 Proposals

CalCCA submitted comments via template, as requested by ED staff, which were included in the Report. To provide clarity on CalCCA's positions on the scoping questions and proposals from WG 1, CalCCA presents a summary in Table 1, below.

Table 1: CalCCA Summary of Position on WG 1 Proposals

Scoping Memo Question	*CalCCA Position on Party Proposals*
3a. How should wholesale market prices be incorporated into demand flexibility price signals?	CalCCA supports proposals utilizing day ahead market prices. CCAs are diverse and will need to determine correct methodologies for marginal generation capacity costs and revenue neutral adders for demand flexible rates.
3b. What options should be provided to help customers plan and manage their bills (e.g., customer load shape subscriptions, forward transactions, bill protections)?	CalCCA does not oppose or support one bill protection method over another. CCAs will need to determine the best bill protection methods for their customers. CalCCA supports gathering more data from pilots to inform selecting bill protection methods. CCAs may have difficulty implementing subscriptions if the data required to compute the subscription is difficult to access or acquire by the CCA in the time needed. As subscription rates are developed, the Commission should ensure that CCAs have access to the necessary data required to design and bill for subscription rates.
3c. How should the timing of customer exports be aligned with grid needs to reduce greenhouse gas emissions, reduce curtailment of renewable energy, and enhance system reliability?	The dynamic rates developed in this proceeding should avoid creating unintended conflicts with other rates that involve customer exports. CalCCA agrees with the Joint IOU proposal that Non-Net Energy Metering, Non-Qualifying Facility export compensation may raise questions about the boundary between retail and wholesale jurisdiction.

Scoping Memo Question	*CalCCA Position on Party Proposals*
3d. How should demand flexibility design consider the barriers and needs of low-income and disadvantaged communities and advance the Commission's Environmental and Social Justice (ESJ) Action Plan goals?	CalCCA generally supports proposals to develop marketing, education, and outreach (ME&O) for low-income customers and customers in disadvantaged communities (DACs), recognizing that these customers may have less flexible load or less access to supporting technologies such as smart thermostats.
3e. How should demand flexibility rates be designed to enable all load serving entities to have the option to participate?	CalCCA generally supports proposals to provide LSEs with the option to either: (1) design their own demand flexible rate independently, or (2) adopt the generation component of the bundled rate for their customers.
3f. How should demand flexibility rates be designed to comply with the California Energy Commission's (CEC) amendments to the Load Management Standards (LMS)?	CalCCA recognizes the importance of designing demand flexible rates to comply with LMS requirements at the outset to minimize future rate changes and complexity. For this reason, CalCCA supports proposals to use LMS to inform the design of demand flexible rates.

B. The Commission Should Continue to Collect and Assess Data to Inform RTP Rate Design

The Commission should continue to collect and assess data from the RTP pilots to inform RTP rate design. Party comments in the Report reflect the complexity and novelty of RTP rates by calling for more data collection to determine various aspects of the RTP rate design. In comments on WG 1 proposals included in the Report, parties such as the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), the California Large Energy Consumers Association (CLECA), the Joint IOUs, Valley Clean Energy (VCE), Polaris Energy Services (Polaris), and Gridtractor Inc. (Gridtractor) recommend pursuing pilots to test implementation of RTP rates.[16] The Commission is currently exploring expansion of existing RTP pilots, including both the PG&E/VCE Agricultural Flexible Irrigation Technology (AgFIT) pilot and SCE's RTP pilot.[17] These pilot expansions will provide valuable insights into unanswered questions around implementation of dynamic rates including rate design for different customer classes, automating load shifting, ME&O, and customer acceptance. With insights gathered further through the expanded pilots, the Commission and LSEs can make informed decisions about how to design RTP rates to maximize grid reliability benefits and provide value to customers.

C. The Commission Should Continue to Facilitate Data Sharing and Collection Between IOUs and CCAs for Successful Implementation of RTP Rates

As RTP pilots are expanded and IOUs and CCAs work together to implement dynamic rates, the Commission should continue to address data access issues identified by CCAs for successful implementation of RTP rates. CalCCA presented data-related barriers to participation in dynamic rates in WG 2 and expands on these below in Section IV.D. Parties also recognize the importance of addressing data sharing and access issues in comments on WG 1 proposals in the Report. For example, the Clean Coalition believes that "a greater level of coordination and data sharing with CCAs is necessary than has been the case in the past to successfully implement real time rates for unbundled customers as well as bundled customers."[18] 350 Bay Area

---

[16] *Id.*, at 24 (Cal Advocates argues for the need for more pilots to test two-part tariffs with customer load-shape subscriptions before implementing at full scale); *see also id.,* at 14 (CLECA recommends to pursue dynamic rates at the pilot stage before expanding significantly); *see also id.,* at 27 (Joint IOUs recognize the need for pilots to find the balance between customer protection and customer understandability); *see also id.,* at 28 (VCE, Polaris, and Gridtractor jointly point out that results from pilots are not available yet to tease out the effectiveness of two-part subscriptions).

[17] *See* R.22-07-005, *Administrative Law Judge's Ruling on Track B Staff Proposal to Expand Existing Pilots* (Aug. 15, 2023) (ALJ Ruling on Expanding Pilots): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M517/K407/517407755.PDF.

[18] Report, at 101.

commented that the Joint IOU proposal to "'[work] with the CCAs to eliminate barriers' is inadequate given history of delay in e.g. data availability."[19] CalCCA appreciates parties acknowledging the need to continue to improve data sharing and access for CCAs to implement RTP rates. Along with continuing to gather data on RTP rate implementation through pilots, the Commission should improve IOU/CCA data sharing processes and access.

D. LSEs Should Pursue TOU and CPP Rates in Parallel to RTP Rates to Maximize Near-Term Load Shifting Impacts

As the Commission contemplates guidance for RTP rates and assesses data from ongoing and future RTP pilots, LSEs should pursue expansion of TOU and CPP rates. Though RTP pilots are underway (and may be expanded) and have provided valuable experience so far, the need to shift loads to support grid reliability statewide exists now. The LMS requires LSEs to offer dynamic rates beginning in 2026, and ED staff have proposed that the expanded dynamic rate pilots run from 2024-2027.[20] Therefore a gap will exist between now and 2026 without large-scale adoption of dynamic rates. CLECA recognizes this gap in comments to WG 1 proposals in the Report, stating that:

> [s]ince TOU rates incentivize customers to shift their loads outside of the on-peak period, load shifting will be maximized if the overall number of customers on time differentiated rates (both dynamic and TOU) is maximized. Thus, going forward the Commission should not limit its focus to dynamic rates.[21]

350 Bay Area also proposes to implement RTP rates "as soon as practicable in parallel with efforts to improve TOU and other dynamic programs."[22] The parallel implementation of TOU and CPP rates will be complementary to RTP rate development because TOU and CPP rates

[19] *Id.*, at 100.
[20] ALJ Ruling on Expanding Pilots, Attachment A - *Staff Proposal on Existing Dynamic Rate Pilot Expansion*, at 4.
[21] *See* Report, at 14-15.
[22] *Id.*, at 82.

already exist, are being implemented, will incentivize load shifting, and will allow LSEs to expand ME&O efforts to increase load shifting while RTP rates are tested with customers.

E. The Commission and Stakeholders Should Continue to Define ESJ Goals Within RTP Rate Design

The Commission and stakeholders are still early in RTP rate development but should continue to define ESJ goals and emphasize equity within RTP rate design. The Scoping Memo established an emphasis on equity and ESJ goals through Question 3.d. which asks, "[h]ow should demand flexibility design consider the barriers and needs of low-income and disadvantaged communities and advance the Commission's [ESJ] Action Plan goals?"[23] In the Report, comments from the Center for Accessible Technology (CforAT) and 350 Bay Area demonstrate a desire to see more direct engagement with Scoping Question 3.d. from the ED proposal. CforAT states that:

> [t]he ED proposal does not meaningfully grapple with the question of how to consider barriers and needs of low-income and disadvantaged communities. In its single page addressing the issue, Energy Division attempts to identify implications of its proposal on the Commission's ESJ Action Plan Goals but presents no substantive recommendations on how to address the implications.[24]

350 Bay Area takes a higher-level view but agrees that the ED proposal "does not appear to directly address ESJ, DAC, and low-income issues."[25] Additionally, while CalCCA supports the high-level strategies the Joint IOUs propose in response to Question 3.d., the Joint IOUs did not provide many details beyond the need to craft ME&O for low-income and DAC customers and the potential need for technology incentives.[26] Though planning to make dynamic rates consistent with the Commission's ESJ goals and to support low-income and DAC customers is

---

[23] Scoping Memo, at 4-5.
[24] Report, at 32.
[25] *Ibid.*
[26] *Id.*, at 97.

important, the process of developing dynamic rates is still early. Without more experience with expanded RTP pilots, the Commission and stakeholders cannot know precisely how to address Question 3.d. of the Scoping Memo. Continued emphasis on ESJ goals and equity is vital to determining specific strategies to ensure that dynamic rates can help both California's grid reliability and all customers.

IV. CALCCA COMMENTS ON WORKING GROUP 2 PROPOSALS

Working Group 2 was tasked with ensuring <u>access</u> to <u>dynamic electric prices</u> by the following: (1) bundled customers; (2) unbundled customers; (3) devices; (4) distributed energy resources; and (5) third party providers.[27] Therefore, the Commission asked WG2 to determine the <u>systems and processes</u> that the Commission should authorize to ensure such <u>access</u> to <u>prices</u> and <u>responding to price signals</u>.[28] The Commission tasked WG2 with considering systems and processes that should be authorized for:

- Computation of dynamic prices for bundled and unbundled customers (Question 4.a.);
- Enabling LSEs to offer unbundled customers the option to take service on dynamic prices (Question 4.b.);
- Enabling third-party service providers to offer demand flexibility services to customers (Question 4.c.);
- Enabling customers to optimize and pre-schedule their energy use to provide demand flexibility (Question 4.d.).

In addition, the Commission asked WG 2 to determine the costs of such systems and processes, and how these costs should be recovered (Question 4.e.). Finally, the Commission asked how the systems and processes should be managed and overseen (i.e., by IOUs or third-parties?) (Question 4.f.).

---

27 Scoping Memo, at 5.
28 *Ibid.*

CalCCA appreciates the Commission's commitment to ensuring the systems and processes ordered and developed from this proceeding "support widespread adoption of demand flexibility rates."[29] Therefore, while CCAs will not be required to adopt the dynamic pricing rate design adopted by the Commission in this proceeding, CCAs share the Commission's goals of reliability, affordability, reduction of renewable energy curtailment, lowering emissions, and enabling electrification through demand flexibility policies.

Consistent with its Comments in the Working Group and on the draft Report, CalCCA provides comments below on (1) the price portal (Question 4), (2) the proposed price machine (Question 4.a.), (3) enabling CCA customers to take service on dynamic electricity prices (Question 4.b.), and (4) costs and cost recovery for the dynamic pricing systems and processes (Question 4.e.). CalCCA reserves the right to comment on other aspects of the Report as the dynamic pricing rate design is further developed, and other issues are raised concerning the systems and processes necessary to support dynamic pricing.

A. Summary of CalCCA Positions on WG 2 Proposals

CalCCA submitted comments via template, as requested by ED, which were included in the Report as part of the WG 2 process. To provide clarity on CalCCA's positions on the scoping questions and proposals from WG 2, CalCCA presents a summary in Table 2.

Table 2: CalCCA Summary of Position on WG 2 Proposals

Scoping Memo Question	***CalCCA Position on Party Proposals***
4. How should the Commission ensure access to dynamic electricity prices by bundled and unbundled customers, devices, distributed energy resources, and third-party service providers? What systems and processes should the Commission authorize for access to prices and responding to price signals?	Utilize the existing CEC MIDAS system as the price portal, with necessary upgrades determined by the Commission and the CEC.

29 *Id.*, at 6.

<table>
<tr><th>Scoping Memo Question</th><th>CalCCA Position on Party Proposals</th></tr>
<tr><td>4.a. What systems and processes should the Commission authorize for computation of dynamic prices for bundled and unbundled customers?</td><td>CalCCA generally supports Energy Division’s proposal for a price machine, including:
• The primary option to house the price machine in a third-party independent of the IOUs; and
• Ensuring access to the price machine by LSEs electing to participate to offer a dynamic generation component of the composite, dynamic price, even if their LSE has not adopted the DFOIR rate design.</td></tr>
<tr><td rowspan="5">4.b. What systems and processes should the Commission authorize to enable load serving entities to offer unbundled customers the option to take service on dynamic electricity prices?</td><td>CalCCA provided barriers to CCAs offering dynamic pricing during the Working Group process. Details of the barriers, and each of the IOUs’ proposals (and CalCCA’s responses) are provided in the Working Group Report.[30] The barriers fall into the following categories, but in some cases vary in each service territory as noted below. In the comments below, CalCCA provides the status of both the IOUs and CalCCA addressing the identified barriers.</td></tr>
<tr><td>1. Customer Usage Data
a. PG&E Service Territory
i. CCA access to non-billing quality interval data for CCA forecasting
ii. CCA access to billing-quality interval data
b. SCE Service Territory
i. CCA access to non-billing quality interval data for CCA forecasting
c. SDG&E Service Territory
i. CCA access to non-billing quality interval data for CCA forecasting</td></tr>
<tr><td>2. Data Regarding Customer Enrollment in DR Programs, including the Emergency Load Reduction Program (ELRP) (all IOU service territories)</td></tr>
<tr><td>3. Equivalent Bill Presentment (all IOU service territories)</td></tr>
<tr><td>4. Customer Rate Change Mechanisms (all IOU service territories)</td></tr>
</table>

30 *See* Report at 233-252.

Scoping Memo Question	*CalCCA Position on Party Proposals*
4.c. What systems and processes should the Commission authorize to enable third-party service providers (e.g., automation service providers, device manufacturers) to offer demand flexibility services to customers?	No position at this time.
4.d. What systems and processes should the Commission authorize to enable customers to optimize and pre-schedule their energy use to provide demand flexibility (e.g., forward transactions)?	No position at this time.
4.e. What are the costs associated with these systems and processes (for access to prices and responding to price signals), and how should these costs be recovered?	*See* Section IV.E., below.
4.f. How should these systems and processes (for access to prices and responding to price signals) be managed and overseen (e.g., utility administration or third-party administration)?	*See* CalCCA position on Question 4.a., above. Otherwise, no position at this time.

B. The Commission Should Adopt WG 2's Recommendation to Utilize the MIDAS System as a Price Portal, with Necessary Upgrades as Determined by the Commission and the CEC

The Commission should adopt the Working Group's recommendation to utilize the existing MIDAS platform as the system to allow customers to access prices and respond to price signals.[31] However, MIDAS will need significant improvements to meet the needs set forth in the Scoping Memo. The Working Group characterizes MIDAS as an "[i]nternet-based price server developed by the CEC to get "prices to devices" in support of the CEC's Load Management Standards and load flexibility in California."[32] However, as noted by the Joint IOUs, it is unclear whether MIDAS will ultimately hold forecast prices generated by the price machine or transactive system, or if MIDAS should only contain final prices.[33] In addition, LSEs

[31] *Id.*, at 189.
[32] *Ibid.*
[33] *Ibid.*

have recently encountered challenges even uploading their time-dependent rates to MIDAS in compliance with LMS, with MIDAS seemingly unable to support the number of rates being uploaded without error alerts, delays, and significant issues with the system. Upgrades and further development to MIDAS will be necessary for it to work as envisioned by the Working Group, in concert with the price machine and to ensure customer access to dynamic pricing. If sufficient upgrades to MIDAS cannot be made, the Commission should consider other options for the price portal.

C. Energy Division's Price Machine Proposal Should be Adopted

CalCCA generally supports ED's price machine proposal set forth in the Report. ED's price machine is designed to compute time-dependent, composite electricity prices (including capacity cost components and time and location dependent wholesale market energy price component as inputs) and upload them with their unique rate identification numbers to the price portal and billing system.[34] While many aspects of the price machine remain uncertain, CalCCA's support at this point of the functionality of the price machine is on a theoretical level. CalCCA reserves the right to comment further as more information is gathered concerning the price machine components and costs, as well as the DFOIR rate design. In addition, systems and processes being developed in the CEC LMS proceeding may impact the price machine, and CalCCA reserves the right to comment further on the price machine as the LMS components are constructed.

CalCCA supports the updates to the price machine provided in the revised ED proposal in the Report. First, CalCCA supports ED's recommendation to have as the "primary option" one consolidated price machine constructed on a statewide basis operating independently from the IOUs (rather than one price machine per IOU).[35] Housing the price machine outside of the IOUs

---

34 *Id.*, at 213.
35 *Id.*, at 216.

will promote a level playing field between the IOUs and participating LSEs, promote efficiencies, and prevent duplication of efforts and multiple vendors. Second, CalCCA also supports ED's proposal to allow all LSEs to elect to participate, regardless if the LSE adopts the DFOIR rate design.[36] Finally, ED correctly delineates the price functions for the price machine, including that LSEs provide the generation price function only, and that the IOU and transmission operator will separately provide the distribution and transmission components.[37]

D. The Commission Must Address the Barriers Identified by CalCCA in the Report to Enable CCAs to Offer Dynamic Pricing

As noted in the Scoping Memo, Question 4.b., the Commission is considering the systems and processes necessary to enable LSEs to offer unbundled customers the option to take service on dynamic electricity prices.[38] While CCAs will not be required to adopt the DFOIR rate design, CCAs are required by the CEC LMS to offer either marginal-cost based rates or programs to encourage the use of electrical energy at off-peak hours and the control of daily seasonal peak loads.[39] As noted above, CCAs are committed to adopting policies that encourage load shifting away from off-peak hours to increase grid reliability.

As noted in the summary chart above, CalCCA presented during the WG 2 process the systemic and process-related barriers known at this time for CCAs to offer dynamic pricing to unbundled customers, along with potential solutions. Also as noted in the summary chart above, these barriers include access to data from the IOUs on customer usage and data regarding customer enrollment in DR programs, potential non-equivalent bill presentment between bundled

[36] *Ibid.*
[37] *Id.*, at 214.
[38] Scoping Memo, at 5.
[39] CEC LMS §§ 1621(a), 1623.1(b).

and unbundled customers, and complexities surrounding customer rate changes once third-party automation providers become involved in the dynamic pricing offerings.

The Report provides in depth descriptions of the barriers, along with solutions proposed by both CalCCA and the IOUs, as well as stakeholder comments on the identified barriers. In general, CalCCA notes that stakeholders generally support the need of unbundled customers to participate in demand flexibility and dynamic pricing, as well as the need for the IOUs to address and solve the existing data sharing issues between the IOUs and CCAs (as discussed in the Report and below). For example, 350 Bay Area "strongly supports the need of unbundled customers to participate in DF," and states that "[t]he CCA data and billing needs are reasonable and ED/CPUC should hold IOUs accountable."[40] Cal Advocates encourages the Commission to "determine logistics for allocation and cost recovery of funding for CCA and IOU data sharing or upgrades to the existing data sharing platforms."[41] Cal Advocates also recommends that the IOUs "explore and consider using non-ratepayer funding sources such as CEC or State General Fund funding" for the upgrades. The Small Business Utility Advocates support the IOU consideration of the issues raised by CCAs to facilitate their enablement, agreeing with the CCAs "that these are important issues."[42] Finally, Utility Consumers' Action Network requests that the IOUs "provide a credible detailed explanation as to why it continues to be challenging to provide the same data [that the IOUs have] in an accurate and reliable fashion to CCAs…."[43]

The following provides updated information on each of the identified barriers for CCAs to offer dynamic pricing, and recommendations for the Commission.

---

40 Report, at 247.
41 *Id.*, at 247.
42 *Id.*, at 251-52.
43 *Id.*, at 252.

1. The Commission Should Require the IOUs to Provide CCAs Access to Customer Usage Data

Historically, CCAs have had difficulty accessing both non-billing quality and billing quality usage data from the IOUs. The following details the data access issues CCAs in each service territory have identified as potential barriers to their offering dynamic rates, and recommendations for the Commission on ensuring these barriers are resolved.

a. CCAs in PG&E Service Territory

i. The Commission Should Require PG&E to Provide Billing Quality Usage Data to CCAs at Hourly or Sub-Hourly Intervals

The Commission should require PG&E to provide billing quality usage data to CCAs at hourly or sub-hourly intervals. As noted in the Report, CCAs in PG&E's service territory do not currently receive billing quality usage data at the hourly (or sub-hourly) interval, which will be crucial for CCAs to bill customers on hourly (or sub-hourly) dynamic rates.[44] Instead, customer usage data, provided at the end of each billing period, is only aggregated down to PG&E's TOU periods. PG&E's billing transactions – the only reliable source of billing quality usage data – are presently aggregated down to PG&E's own pre-defined TOU periods.

As noted in the Report, PG&E proposes to upgrade its existing EDI system to support billing quality interval data for up to 600,000 service address IDs (SAIDs), including those of CCA customers, by December 2023.[45] This upgrade will serve as an interim step to address the need for such interval data prior to completion of PG&E's billing system upgrade (which will enable the provision of such data to CCAs) in approximately July, 2026.[46] CalCCA requests that the Commission order PG&E to ensure the interim and complete upgrades will occur to ensure

---

44 *Id.,* at 233-34.
45 *Ibid.*
46 *Ibid*.

CCAs gain access to the billing quality usage data at the hourly or sub-hourly level. In addition, while the status of the interim upgrade is currently unknown, CalCCA recommends that the Commission require PG&E to provide regular updates to the CCAs in PG&E's service territory regarding PG&E's progress toward implementation of both the interim and final billing system upgrades. Finally, CalCCA requests that the Commission institute an overall requirement in this proceeding that all IOUs provide such billing quality meter data to CCAs to ensure they can offer dynamic rates.

ii. CCA Access to PG&E Non-Billing Quality Hourly Customer Interval Usage Data is Necessary for CCA Load Forecasting

CCAs in PG&E's service territory receive non-billing quality hourly interval data through PG&E's ShareMyData (SMD) platform. LSEs such as CCAs need such data for load forecasting. Accurate forecasting (including day-ahead load forecast submissions to the California Independent System Operator) promotes load management and grid reliability especially during grid stress events. PG&E commits to providing data through SMD within 48 hours of power flow. However, as detailed in the Report, the CCAs have experienced many instances of substantial delays in the data, as well as unplanned outages and certification issues with the platform.[47]

As pricing becomes more time-dependent (i.e., for both TOU and dynamic rates), the need for accurate data for load forecasting becomes heightened. Without such data, CCAs will incur additional costs for inaccurate scheduling, potentially resulting in inflated prices and further exacerbating grid reliability issues that both TOU and RTP are designed to improve.

While PG&E appears to agree with the CCAs' need for hourly interval data (non-billing

---

[47] *Id.* at 182-183, 234-235, and 248.

quality) within at least 48 hours for load forecasting, PG&E believes that instances of missing or delayed data are isolated to a very small percentage of SAIDs that are encountering metering issues and disagrees that the SMD system is not performing as advertised. CalCCA requests that the Commission order the SMD issues be addressed in a working group between PG&E and CCAs in its service territory to determine potential reliability improvements. While PG&E has been generally responsive to individual instances of CCA difficulties with SMD, the CCAs believe that systemic problems with SMD are preventing accurate and low-latency transmission of the data to CCAs. After identification of the systemic problems, PG&E and the CCAs can report back to the Commission to identify any potential solutions.

b. CCA Access to SCE Non-Billing Quality Hourly Customer Interval Usage Data is Necessary for CCA Load Forecasting

During the Working Group process, CalCCA identified barriers for CCAs in SCE territory to offer dynamic pricing due to the CCAs not receiving (non-billing quality) hourly interval data from SCE until the close of the billing cycle (i.e., 29-31 days after power flow).[48] Lack of timely data hampers CCA load forecasting and will prevent CCAs from timely tracking load correlation from real-time pricing. As such, the Commission should institute a requirement that all IOUs provide such near-time non-billing quality meter data to CCAs to ensure they can offer dynamic rates.

In the Working Group process, SCE informed CCAs that it would soon be implementing its cloud-based Snowflake platform that can provide CCAs with the “raw” or unbilled interval data within two business days after power flow.[49] SCE noted that it expected rollout of the Snowflake platform in the fourth quarter of 2023. As of the date of this filing, the CCAs

[48] *Id.*, at 239.
[49] *Id.*, at 240.

commend SCE for their efforts involving CCAs in the testing of the new system. SCE has been supportive of CCA teams integrating SCE's new system, and the CCAs in SCE's territory look forward to continuing to work with the SCE team to successfully implement the Snowflake platform. CalCCA requests that the Commission order SCE to continue to provide ongoing support to CCA teams with respect to utilizing the platform, and that SCE provide ongoing updates on the schedule for implementation.

c. CCA Access to SDG&E Non-Billing Quality Hourly Customer Interval Usage Data is Necessary for CCA Load Forecasting

During the Working Group process, CalCCA identified barriers for CCAs in SDG&E's territory to offer dynamic pricing due to the CCAs not receiving (non-billing quality) hourly interval data from SDG&E until the close of the billing cycle (i.e., 29-31 days after power flow).[50] Currently, with TOU rates and in the future to provide dynamic pricing, lack of timely data hampers CCA load forecasting and will prevent CCAs from timely tracking load correlation from real-time pricing. During the Working Group process, SDG&E stated that it is building a technical solution for providing near real-time interval data, as described in detail in the Report.[51] SDG&E reported that it expected to have its solution complete in early fourth quarter 2023. SDG&E filed an Advice Letter seeking to add a new line-item fee to its schedule for CCAs to access the data through the new self-service interface.[52] The CCAs in SDG&E's service territory filed a response on October 16, 2023, commending SDG&E for proposing a solution to the barriers preventing the Joint CCAs from offering dynamic pricing rate options.[53] Consistent

---

50 *Id.*, at 239.
51 *Id.,* at 243.
52 *See* Tier 2 Advice Letter 4288-E, *San Diego Gas & Electric Company's Update to Schedule CCA to Add a New Service for Near Real-Time Interval Meter Data Access* (Sept. 26, 2023).
53 *See Response of San Diego Community Power and Clean Energy Alliance to San Diego Gas & Electric Company Advice Letter 4288-E* (Oct. 16, 2023).

with the CCAs' request in response to SDG&E's Advice Letter, CalCCA requests herein that the Commission require all IOUs to provide such near-real time meter data access in this proceeding to ensure CCAs can offer dynamic rates.

2. In the Event Dual Enrollment Between Demand Response Programs and Demand Flexible Rates is Prohibited, CCAs Must Have Access to Data Regarding CCA Customer Enrollment in Such Programs

In the event dual enrollment is prohibited between certain DR programs (such as ELRP) and dynamic pricing, the Commission must address the data needs of CCAs to prevent such dual enrollment. For example, in PG&E's service territory, CCAs currently cannot get access to the identity of their customers enrolled in DR and ELRP programs. PG&E provided an extensive explanation of the issues surrounding providing such information, and the parties ultimately agreed to address these issues in the PG&E DR application proceeding, A.22-05-002.[54] However, whether the dual enrollment issues will be addressed in that proceeding are uncertain, and such data sharing should be aligned across the IOUs. Currently, SCE has agreed to provide such information in its weekly reporting, and SDG&E has stated that it already provides such information (although the CCAs in SDG&E's service territory have pointed out that SDG&E does not provide customer identifiers for all DR programs that customers are enrolled in).[55] Given the disparity between IOU practices in sharing customer DR enrollment information, the Commission should establish requirements for IOUs to share such data in the context of demand flexibility. In addition, the Commission will need to address whether dual enrollment between certain programs will be prohibited.[56]

---

[54] Report, at 235-238.

[55] *Id.*, at 240-41, 244.

[56] The Commission is currently considering whether to establish dual enrollment prohibitions in the context of the proposed expanded pilots. *See* ALJ Ruling on Expanding Pilots, *Attachment A - Staff Proposal on Existing Dynamic Rate Pilot Expansion*, at 11-12 (prohibiting customers participating in certain DR programs, including ELRP, from participating simultaneously in the expanded pilots).

3. The Commission Must Ensure Equivalent Bill Presentation for Bundled and Unbundled Customers

During the Working Group process, CalCCA identified the need for equivalent bill presentation for bundled and unbundled customers in the context of dynamic pricing.[57] Given that a CCA customer's bill is provided by the IOUs, it will be important once the rate design and bill presentment issues begin to be addressed in this proceeding that the Commission require the IOUs to present bundled and unbundled customer information equivalently, without the use of IOU "proxies" to demonstrate customer savings on certain rates. The IOUs generally agreed that bundled and unbundled customers should receive identical bill presentment. In addition, SDG&E proposed to create an online portal that will allow bundled and unbundled customers to access detailed customer usage information.[58] CalCCA and the IOUs agreed to discuss this issue, including tools for equivalent bill presentment, further when bill design is addressed in the proceeding (i.e., after rate design is complete).

4. Complexities Regarding Customer Rate Change Requests in the Context of RTP Must be Addressed

The final potential barrier for CCAs offering dynamic rates identified at this time by CalCCA is the complexity that arises in the context of dynamic pricing and potential third-party DR automation with customers wishing to automatically change CCA/IOU rates through DR capable devices. For example, CCAs currently cannot fulfill customer rate change requests – instead, CCA customers wishing to change rates must contact their IOU to make a rate change. CalCCA is not requesting that the CCAs be able to take on the rate change role but is instead flagging that as we move towards automated DR, customer consent and privacy issues may arise. CalCCA and the IOUs all agree that this issue can be addressed in both later phases of this

---

[57] Report, at 238, 241-42, 244-45.

[58] *Id.*, at 245.

proceeding, and also in the LMS proceeding. Indeed, the LMS requires a “single statewide tool” be developed to allow access by third parties to customer rate data in MIDAS.[59] Such a tool may address streamlining the customer rate change process.

E. The IOUs’ Cost Recovery Requests are Premature and Should be Addressed Once the Systems and Process Requirements are Established

1. The Commission Should Reject the IOUs’ Request for the Establishment of a Two-Way Balancing Account for the Development of the Systems and Processes

The Joint IOUs request the Commission authorize and direct the IOUs to file advice letters to establish two-way balancing accounts to facilitate the recovery from all customers of costs for establishing systems and processes for dynamic rate proposals in Track B, and for costs associated with implementing the CEC’s LMS.[60] The Joint IOUs propose that the advice letter process should serve the purpose of setting revenue requirements.

While CalCCA is not wholly opposed to the Joint IOUs utilizing a balancing account to record certain costs, the Joint IOUs’ proposal lacks detail on (1) what categories and types of costs are appropriate to be recorded and collected from all customers, (2) why all such costs should be recovered from all customers, and (3) the specific rate mechanisms by which the Joint IOUs should be allowed to recover those costs. As discussed above by CalCCA, many outstanding questions remain regarding the nature of the systems and processes that will be developed to facilitate the offering of dynamic rates. Additionally, CalCCA notes that the advice letter process is not the appropriate venue to determine cost recovery mechanisms. The advice letter process does not allow for sufficient party input and record development on what costs should be recovered, from whom, and how. As such, CalCCA recommends the Commission

---

59 CEC LMS § 1623(c).

60 Report, at 74.

reject the Joint IOUs' proposal until it rules on how these systems and processes will be developed, who will update and maintain them, and who has access. Once these details are provided, parties should be given the opportunity to comment on cost estimates and the appropriate cost recovery mechanism before advice letters indicating budget and setting revenue requirements are filed.

2. The Commission Should Ensure that all LSEs are Able to Recover Shared Categories of Costs for the Development of Systems and Processes Through the Same Rate Mechanism

To ensure equity and prevent cost shifting between bundled and unbundled customers, CalCCA recommends the Commission ultimately permit CCAs to recover all *shared categories of costs* for systems and process developments through the same rate component, or rate mechanism, that IOUs are permitted to recover that category of cost. If IOUs are allowed to recover shared categories of costs from all customers, but CCAs are required to recover those *same* categories of costs from just their customers, CCA customers will be unreasonably and unnecessarily harmed. To illustrate, if IOUs are permitted to recover all categories of their costs associated with developing systems and process for dynamic rates from all customers through IOU charges, but CCAs are required to recover all of their categories of costs from only CCA customers, for any shared category of cost to develop and administer dynamic rates CCA customers must then pay for those IOU costs through their distribution rates. CCAs must then additionally absorb all costs on the CCA side through their CCA's generation rates, while IOU customers pay only for the IOU specific costs. This places a disproportionate burden on CCAs offering dynamic rates and acts as a disincentive for CCAs to participate in the dynamic rates and utilize the systems and processes that are developed through this proceeding.

To avoid this negative outcome, once the Commission ultimately rules on the cost recovery mechanisms for developing the systems and processes for dynamic rate proposals, the

Commission could permit CCAs to create and submit budgets via advice letter to the Commission, in a similar manner to how the Commission provides consistent cost recovery mechanisms to IOUs and CCAs in the context of disadvantaged community Green Tariff programs,[61] to ensure all customers share equally in the costs of developing dynamic rates.

V. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl,
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

November 13, 2023

[61] *See* D.18-06-027, *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities,* R.14-07-002 (June 22, 2018): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M216/K789/216789285.PDF.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the Self-Generation Incentive Program and Related Issues.	Rulemaking 20-05-012 (Filed May 28, 2020)

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON PROPOSED DECISION EXPANDING ELIGIBILITY FOR THE HEAT PUMP WATER HEATER PROGRAM

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

On behalf of Joint Community Choice Aggregators

November 16, 2023

SUBJECT MATTER INDEX

TABLE OF AUTHORITIES

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the Self-Generation Incentive Program and Related Issues.	Rulemaking 20-05-012

OPENING COMMENTS OF THE JOINT COMMUNITY CHOICE AGGREGATORS ON PROPOSED DECISION EXPANDING ELIGIBILITY FOR THE HEAT PUMP WATER HEATER PROGRAM

The Joint Community Choice Aggregators[1] (Joint CCAs) submit these comments on the *Proposed Decision Expanding Eligibility for the Heat Pump Water Heater Program* (PD) pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission.

I. COMMENTS

As detailed in the Joint CCAs's opening and reply comments on the July 12, 2023 *Assigned Commissioner's Ruling Seeking Additional Comments on Self Generation Incentive Program and Heat Pump Water Heater Program Improvements*, the Joint CCAs support expanding Self Generation Incentive Program (SGIP) Heat Pump Water Heater (HPWH) program eligibility and correspondingly modifying the current definition of a "qualifying demand response program."[2] The Joint CCAs believe that broadening the definition of a qualifying demand response (DR) program—and thereby allowing SGIP HPWH program participants to enroll in a broader array of DR programs—is timely, given the reliability challenges facing the electric grid and the valuable role that DR plays in mitigating those challenges.

---

[1] The Joint CCAs consist of East Bay Community Energy (EBCE), Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), Sonoma Clean Power Authority (SCP) and the City of San Jose.
[2] PD at 14.

Consistent with the Joint CCAs' recommendations, the PD appropriately broadens the current definition of a "qualifying demand response program" by incorporating into that definition programs other than market-integrated supply-side DR programs that count for resource adequacy (RA).[3] The Joint CCAs strongly support including the corresponding definitions from the Demand Flexibility Rulemaking (Rulemaking 22-07-005) or the Investor-Owned Utilities (IOU) DR Program Applications (consolidated A.22-05-002, A.22-05-003, and A.22-05-004).[4] The integration of these definitions offers greater consistency and regulatory clarity vital for related program integration, SGIP HPWH program participation and grid reliability improvements. The Joint CCAs specifically support the inclusion of both load modifying programs focused on *daily load-shifting* and *event-based* load modifying DR programs. For clarification purposes, the Joint CCAs request in this Decision and in the consolidated IOU DR Program Applications A.22-05-002, A.22-05-003, and A.22-05-004 proceedings[5] that the Commission expressly incorporate community choice aggregator (CCA)-administered DR programs into the definition of "qualifying demand response programs." The Joint CCAs note broad party support for the inclusion of CCA-administered programs in that definition.

Finally and relatedly, in *dicta*, the PD requires that IOU customers receiving an incentive through the SGIP HPWH program enroll in a qualifying demand response program, but fails to mention CCA customers. The Order should clarify that this requirement applies equally to IOU and CCA customers.

---

[3] PD at Ordering Paragraph 1.
[4] *Id*. at 15.
[5] Consolidated IOU DR Program Applications A.22-05-002, A.22-05-003, and A.22-05-004, Proposed Decision issued November 6, 2023.

A. The Joint CCAs support including event-based and daily load-shifting load modifying programs in the definition of "qualifying demand response programs."

The Joint CCAs strongly support the Commission including "Any demand response program that meets the definition of a qualified program established by the Commission in the Demand Flexibility Rulemaking (Rulemaking 22-07-005) or the IOU DR Programs Application (A.22-05-002)"[6] in the definition of "qualifying demand response programs."

As stated in its earlier submitted comments,[7] various DR program types and models can help reduce customer demand during peak hours. At a high level, DR programs—which are typically event-based—fall into two categories: California Independent System Operator (CAISO) market-integrated DR programs (also called supply-side DR programs which can help *meet* a load serving entity's (LSE) RA obligation) and load-modifying DR programs (those that can be included on an LSE's peak demand forecast to *reduce* their RA obligation). In addition to event-based DR programs, many LSEs have also recently developed daily load-shifting programs. Daily load-shifting programs are a variant of a "load modifying program" because these programs can also be incorporated into an LSE's forecast to reduce its RA obligations. Certain programs include both daily load-shift and event-based incentives under a single program umbrella. Marin Clean Energy's (MCE) Peak FLEXmarket program, for example, combines both daily load-shift and event-based incentives. Those event-based and daily load-shifting incentives have, in tandem, successfully reduced peak demand and supported grid reliability during periods when the grid is constrained. For instance, in 11 event days during the September 2022 heatwave, the Peak FLEXmarket program achieved more than 39,000 kWhs in energy savings with almost 2,200

[6] PD at 15.

[7] Opening Comments of the Joint Community Choice Aggregators on Assigned Commissioner's Ruling Seeking Additional Comments on Self-Generation Incentive Program and Heat Pump Water Heater Program Improvements (Aug. 1, 2023).

participating resources. The program achieved an additional 30,000 kWhs in energy savings from daily load-shifting during the summer months (June 1 – October 30)—equivalent to taking about 300 residential customers off the grid during peak hours. MCE's PeakFLEX market program aptly illustrates the peak demand reduction value of both event-based *and* daily load-shifting load modifying DR programs.

For the above reasons, the Joint CCAs support the inclusion of both event-based and daily load shifting load-modifying programs in the Commission's updated definition of "qualifying demand response programs."[8]

B. The Order should clarify that CCA-administered programs are incorporated into the definition of a "qualifying demand response program."

The Order should clarify that "qualified demand response programs" for IOU and CCA customers are defined irrespective of whether the program is administered by an IOU, CCA or third-party Demand Response Provider (DRP). Several parties, including the Joint CCAs, expressed support in their comments for modifying the definition of "qualifying demand response programs" to explicitly include CCA-administered programs.[9] As the Joint CCAs noted in comments, CCAs already administer—and plan to launch—several load-modifying DR programs available to HPWHs. The PD acknowledges CCA-administered DR programs (*see* PD at 11, stating "[c]ertain current Community Choice Aggregator (CCA) and IOU load-shifting programs are designed to shift energy use of HPWHs away from peak hours"), but does not clearly identify CCA-administered programs as falling within the definition of a "qualifying demand response program." The PD also wisely acknowledges, "Revising the definition of a qualifying demand

8 PD (OP 1 Section 2).

9 *See* Opening Comments of the Joint CCAs on Assigned Commissioner's Ruling Seeking Additional Comments on Self-Generation Incentive Program and Heat Pump Water Heater Program Improvements at 3 (Aug. 1, 2023); Reply Comments of the Joint CCAs on Assigned Commissioner's Ruling Seeking Additional Comments on Self-Generation Incentive Program and Heat Pump Water Heater Program Improvements at 2 (Aug. 11, 2023).

response program for electric IOUs, RENs, and CCAs is a reasonable step for expanding SGIP HPWH program participation."[10] The Order should clarify that "qualifying demand response programs" include CCA-administered programs, such that customers installing HPWH have the flexibility to benefit the grid through a spectrum of strong program options.

The Joint CCAs' recommended modifications to the definition of a "qualifying demand response program" for the purposes of SGIP HPWH eligibility are provided in Appendix A to these comments.

C. The Order should clarify that CCA customers receiving an incentive through the SGIP HPWH program must enroll in a qualifying demand response program.

In *dicta*, the PD requires that the SGIP HPWH Program Implementer "enroll **electric IOU customers** who receive an incentive through the program in a CAISO market-integrated DR program," and further requires that "those customers also enroll in a HPWH load-shifting program, if one is available in the customer's service territory."[11] The Joint CCAs assume that the PD intended to apply this requirement not only to IOU customers, but also to CCA customers, based on the language of Ordering Paragraph 1.ii, which references CCA customers.[12] Customers can receive electric service from an IOU, a publicly owned utility (POU) or a CCA. Regional Energy Networks (REN) run programs but do not provide electric service. The Order should make changes to the *dicta* on page 14 to clarify that CCA customers receiving an incentive through the SGIP HPWH program must enroll in a qualifying demand response program and enroll in a HPWH load-shifting program if one is available in the customer's service territory. To that end, the Joint CCAs

---

[10] PD at 21 (Conclusions of Law 2).

[11] *Id*. at 14 (emphasis added).

[12] The Joint CCAs note that Ordering Paragraph 1.ii. also references "customers of. . . Regional Energy Networks." Regional Energy Networks (RENs) are not load serving entities (LSEs) and do not have "customers." Joint CCAs therefore suggest removing the reference to Regional Energy Networks in Ordering Paragraph 1.ii (*See* Appendix A).

recommend the following redline on page 14 of the PD: "Therefore, we require that the SGIP HPWH program PI enroll electric IOU <u>and CCA</u> customers who receive an incentive through the program in a CAISO market-integrated DR program, and further require that those customers also enroll in a HPWH load-shifting program, if one is available in the customers' service territory."

II. CONCLUSION

The Joint CCAs appreciate the Administrative Law Judge's efforts in thoughtfully addressing the parties' comments with respect to the definition of a "qualifying demand response program" and respectfully request the Commission adopt the revisions discussed in these comments and detailed in Appendix A.

Respectfully submitted,

____

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

On behalf of Joint Community Choice Aggregators

Dated: November 16, 2023

APPENDIX A

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, the Joint CCAs provide this Appendix setting forth proposed changes to the ordering paragraphs in the *Proposed Decision Expanding Eligibility for the Heat Pump Water Heater Program*. The Joint CCAs' proposed revisions appear in underline and strike-through.

Ordering Paragraphs

Ordering Paragraph 1: The new definition of a qualifying demand response program for the Self-Generation Incentive Program Heat Pump Water Heater (HPWH) program is:

i. For customers of electric publicly-owned utilities:

  A program whose technology or technologies (1) shifts onsite energy use to off-peak time periods or reduces demand from the grid by offsetting some or all of the customer's onsite energy load, including, but not limited to, peak electric load; (2) is commercially available; (3) safely utilizes the existing transmission and distribution system; and (4) improves air quality by reducing criteria air pollutants and greenhouse gas emissions.

ii. For customers of electric investor-owned utilities (IOU), ~~Regional Energy Networks~~, and Community Choice Aggregators (CCA) irrespective of whether the administrator is an IOU, CCA, or third-party Demand Response Provider (DRP):

  a. A California Independent System Operator market-integrated supply-side program that counts toward a load-serving entity's resource adequacy obligations; or

  b. Any demand response program that meets the definition of a qualified program established by the Commission in the Demand Flexibility Rulemaking 22-07-005 or the IOU Demand Response Programs Application 22-05-002; and

  c. Where available, a program whose technology or technologies shifts onsite energy use to off-peak time periods or reduces demand from the grid by offsetting some or all of the customer's onsite water heater energy load, including, but not limited to, peak electric load (*e.g.*, the WatterSaver program for Pacific Gas & Electric Company customers and the Smart HPWH program for Southern California Edison Company customers).

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 ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON ASPECTS OF NET VALUE BENEFIT TARIFF PROPOSAL

Brittany Iles
BRAUN BLAISING & WYNNE, P.C.
555 Capitol Mall, Suite 570
Sacramento, CA 95814
Telephone: (916) 326-5812
E-mail: iles@braunlegal.com

November 27, 2023

Attorney for the
Joint Community Choice Aggregators and
City and County of San Francisco

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 ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON ASPECTS OF NET VALUE BENEFIT TARIFF PROPOSAL

I. INTRODUCTION

In accordance with the California Public Utilities Commission's ("CPUC or "Commission") *Administrative Law Judge's Ruling Setting Aside Submission of the Record to Seek Comments on Aspects of Net Value Benefit Tariff Proposal,* dated November 6, 2023 ("ALJ Ruling"), Clean Power Alliance of Southern California ("CPA"), the City and County of San Francisco, acting by and through its Public Utilities Commission ("CleanPowerSF"), East Bay Community Energy ("EBCE") [1], 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

[1] Pending formal filing with the Commission of EBCE's name change to Ava Community Energy ("Ava"), Ava will continue to file as EBCE in this proceeding until further notice, and will be referenced as EBCE in this filing.

Clean Energy ("SJCE") (collectively, the "Joint Community Choice Aggregators" or "Joint CCAs") hereby submit these Opening Comments.

The Joint CCAs appreciate the Commission's aim to answer remaining questions and gaps associated with the Coalition for Community Solar Access' ("CCSA's") Net Value Benefit Tariff[2] ("NVBT") proposal. If the Commission chooses to adopt a version of the NVBT proposal, it is imperative that all aspects of the proposal are fully vetted and any open questions answered to ensure the resulting program benefits California ratepayers and the grid. First, however, the Joint CCAs continue to support and advocate for the continuation and improvement of the existing Green Access Programs ("GAPs") and hold that determinations made on the NVBT should not impact those existing programs.[3] Next, the Joint CCAs argue that the proposed valuation and treatment as behind-the-meter ("BTM") resources is inaccurate for NVBT projects and may result in potential material impacts to resource adequacy ("RA"). Finally, the Joint CCAs are concerned that some of the issues contained in the Questions included as Attachment 1 to the ALJ Ruling require determinations for NVBT resources that are contrary to prior Commission proceedings and decisions on RA and interconnection. The Joint CCAs stress the importance of ensuring that any determinations made for the NVBT proposal are consistent with the Commission's treatment of other resources to avoid creating uncertainty or unintended consequences across other Commission proceedings.

---

[2] Previously referred to as the Net Value Billing Tariff in prior Joint CCA filings in this proceeding.

[3] *See* Opening Brief of the Joint Community Choice Aggregators and City and County of San Francisco.

II. DETERMINATIONS ON CERTAIN ASPECTS OF THE NET VALUE BENEFIT TARIFF PROPOSAL SHOULD NOT IMPACT THE EXISTING GREEN ACCESS PROGRAMS

As a primary matter, the Joint CCAs continue to support and advocate for the continuation and improvement of the current disadvantaged community green tariff ("DAC-GT") and community solar green tariff ("CSGT") programs. Proposals or determinations made with regards to the NVBT proposal should not impact the existing programs, and the Joint CCAs' comments on the NVBT proposal addressed below do not change the Joint CCAs' position with regards to the DAC-GT and CSGT programs. The Joint CCAs have continued to highlight the successes of the DAC-GT and CSGT programs throughout this proceeding, as well as recommend modifications to further expand upon those successes.[4] Since the Joint CCAs last provided data on the current status of the DAC-GT and CSGT programs, additional power purchase agreements have been executed, allocated program capacity has been transferred between program administrators, and the programs have continued to grow and serve low-income customers residing in disadvantaged communities. To highlight this, the Joint CCAs provide the updated tables below to ensure the Commission has the most up-to-date information regarding these programs.[5]

///

---

4 *See Id*. (proposing modifications including, but not limited to, increased program capacity for the DAC-GT program, adoption of a formal process to allocate additional DAC-GT and CSGT program capacity, and expansion of locational requirements for the programs).

5 While the table below provides the most up-to-date information regarding executed Power Purchase Agreements ("PPAs") for new resources, many CCA program administrators that have not yet executed a PPA are currently in negotiations with developers, and the Joint CCAs expect the total procured capacity for CCA program administrators to increase in the coming months.

Table 1: DAC-GT Program Procurement Data as of October 31, 2023

Program Administrator	Allocated Capacity (MW)	Total Procured Capacity (MW) (Defined as signed PPA for new resources)	Percentage of Allocated Capacity Procured
CPA	12.19	12.19[6]	100%
CleanPowerSF	1.826	0[7]	0%
CalChoice	1.31	0[8]	0%
EBCE	5.726	0[9]	0%
MCE	4.646	4.64[10]	99.87%
PCE	3.74	3.00[11]	80%
PG&E	52.32	52.32[12]	100%
SCE	56.5	0[13]	0%
SDCP	15.78	0[14]	0%
SDG&E	2.22	0[15]	0%
SJCE	1.736	1.736[16]	100%

---

6 *See* Quarterly DAC-GT and CSGT Programs Report of Clean Power Alliance of Southern California for Third Quarter 2023, filed in Rulemaking ("R") 14-07-002 on October 17, 2023 ("CPA DAC-GT/CSGT Q3 2023 Report").

7 *See* CleanPowerSF Quarterly DAC-GT and CSGT Program Report for the Third Quarter of 2023, filed in R.14-07-002 on October 25, 2023 ("CleanPowerSF DAC-GT/CSGT Q3 2023 Report). CleanPowerSF currently supplies 1.826 MW of capacity via an interim resource.

8 *See* Joint Quarterly DAC-GT Program Report of City of Lancaster, City of Pico Rivera, and City of San Jacinto for Third Quarter 2023, filed in R.14-07-002 on October 30, 2023 ("CalChoice DAC-GT Q3 2023 Report").

9 *See* Quarterly DAC-GT and CSGT Programs Report for Third Quarter 2023 for East Bay Community Energy, filed in R.14-07-002 on October 30, 2023 ("EBCE DAC-GT/CSGT Q3 2023 Report"). EBCE currently supplies 5.726 MW of capacity via interim resources.

10 *See* Quarterly DAC-GT and CSGT Programs Report for January 1, 2023 to March 31, 2023 of Marin Clean Energy, filed in R.14-07-002 on October 30, 2023 ("MCE DAC-GT/CSGT Q3 2023 Report").

11 *See* Quarterly DAC-GT Program and CSGT Program Report for First Quarter 2023 of Peninsula Clean Energy Authority, filed in R.14-07-002 on October 30, 2023 ("PCE DAC-GT/CSGT Q3 2023 Report"). *See also* Disposition Letter Approving PCE Advice Letter 27-E (January 8, 2023). PCE currently supplies the remaining .74 MW of capacity via interim resources.

12 *See* Quarterly DAC-GT and CSGT Programs Report of Pacific Gas & Electric Company (E 39-E) for the Period of July 1, 2023-September 3o, 2023, filed in R.14-07-002 on October 30, 2023 ("PG&E DAC-GT/CSGT Q3 2023 Report").

13 *See* DAC-GT and CSGT Third Quarter 2023 Report of Southern California Edison Company (E 338-E), filed in R.14-07-002 on October 27, 2023 ("SCE DAC-GT/CSGT Q3 2023 Report") at 3.

14 *See* Resolution E-5246 (approving SDCP as a program administrator in March 2023).

15 *See* Quarterly Disadvantaged Community Green Tariff and CSGT program Process Report of San Diego Gas & Electric Company (U 902 E) Q3 2023, filed in R.14-07-002 on October 31, 2023 ("SDG&E DAC-GT/CSGT Q1 2023 Report"); *see also* Resolution E-5246 (transferring SDG&E DAC-GT and CSGT allocations to SDCP).

16 *See* Quarterly DAC-GT Report for Third Quarter 2023 of San José Clean Energy, filed in R.20-08-020 on October 27, 2023 ("SJCE DAC-GT Q3 2023 Report").

Table 2: CSGT Program Procurement Data as of October 31, 2023

Program Administrator	Allocated Capacity (MW)	Total Procured Capacity (MW) (Defined as signed PPA for new resources)	Percentage of Allocated Capacity Procured
CPA	3.37	3.37[17]	100%
CleanPowerSF	0.5525	0[18]	0%
CalChoice	N/A	N/A[19]	N/A
EBCE	1.5625	0[20]	0%
MCE	1.28	0[21]	0%
PCE	0.4025	0[22]	0%
PG&E	14.2	12[23]	84.5%
SCE	14.63	3[24]	20.51%
SDCP	4.38	0[25]	0%
SDG&E	0.62	0[26]	0%
SJCE	N/A	N/A[27]	N/A

III. THE CURRENT PROPOSED VALUE STACK AND BEHIND-THE-METER TREATMENT DOES NOT ACCURATELY VALUE NET VALUE BENEFIT TARIFF RESOURCES.

The Joint CCAs understand that the current NVBT proposal consists of in-front-of-the-meter ("FTM") resources, as the resources are connected directly to the investor owned utilities' ("IOUs'") distribution grid and are not interconnected behind a customer's meter.[28] It is essential

[17] *See* CPA DAC-GT/CSGT Q3 2023 Report.
[18] *See* CleanPowerSF DAC/CSGT Q3 2023 Report.
[19] *See* Resolution E-5130 (approving CalChoice CCAs as DAC-GT program administrators only).
[20] *See* EBCE DAC/CSGT Q3 2023 Report.
[21] *See* MCE DAC/CSGT Q3 2023 Report.
[22] *See* PCE DAC/CSGT Q3 2023 Report.
[23] *See* PG&E DAC/CSGT Q3 2023 Report.
[24] *See* SCE DAC/CSGT Q3 2023 Report.
[25] *See* Resolution E-5246 (newly approving SDCP as program administrators).
[26] *See* SDG&E DAC/CSGT Q3 2023 Report; *see also* Resolution E-5246 (approving SDCP as a program administrator and transferring SDG&E DAC-GT and CSGT allocations to SDCP).
[27] *See* Resolution E-5124 (approving SJCE as a DAC-GT program administrator only.)
[28] *See* Reply Brief of the Joint Community Choice Aggregators and City and County of San Francisco ("Joint CCA Reply Brief") at 25; *see also* PG&E Rebuttal Testimony at 11 ("The analyses presented in CCSA's testimony are fundamentally flawed because the DER in question is not a demand-side resource. It is a [FTM] generator that is injecting all its energy into the grid and not physically offsetting any of its subscriber customer load."), Reply Comments of Southern California Edison Company (U 338-E) on Administrative Law Judge's Ruling Setting Aside Submission of the Record to Seek Comments on Cost-Effectiveness Considerations ("SCE Cost Effectiveness Reply Comments") at 5.

that these resources are appropriately valued. Based on the Joint CCAs' understanding of the NVBT proposal and Commission precedent, treating these FTM NVBT resources as though they were BTM resources risks compensating facility owners for value that does not actually appear, as explained in more detail below.

a. Response to ALJ Ruling Questions 2 and 3

The Joint CCAs appreciate the Commission's questions regarding Grid Reliability and Capacity Values. As load serving entities ("LSEs") continue to respond to a tight RA market and associated affordability challenges, it is imperative that the state builds resources which address RA needs and are appropriately compensated for the RA value they provide.

The Joint CCAs continue to have concerns regarding the application of the Avoided Cost Calculator ("ACC") to value NVBT resources as proposed by CCSA. The Joint CCAs have raised these concerns in opening and reply comments in response to the ALJ's ruling seeking comments on cost-effectiveness consideration, noting that it is inappropriate to compensate FTM resources using the ACC as the ACC was developed to value the avoided cost of FTM generation when using BTM resources.[29] For example, as noted in the Joint CCAs' opening comments, FTM resources that participate in the NVBT must use the distribution system to deliver energy and as such, some of the avoided costs included in the transmission and distribution adders in the ACC are not appropriate for these resources.[30] PG&E and SCE have

---

[29] *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 Cost-Effectiveness Considerations at 10; *See also* Reply Comments of the Joint Community Choice Aggregators and City and County of San Francisco on Administrative Law Judge's Ruling Seeking Comments on Cost-Effectiveness at 13.

[30] Opening Comments of the Joint Community Choice Aggregators and City and County of San Francisco on Administrative Law Judge's Ruling Seeking Comments on Cost-Effectiveness Considerations at 11.

raised similar concerns in comments and briefing, noting the inaccuracy of the ACC in valuing NVBT resources as FTM resources may not avoid all of the costs contained within the ACC.[31]

The Joint CCAs further appreciate the Commission's question regarding whether "[CCSA's] proposal for capacity generation value is the most optimal methodology to incentivize capacity when the grid needs support," and continue to believe that the blanket application of the ACC for all NVBT resources runs the risk of overcompensating resources for RA which does not actually appear, requiring LSEs to purchase more RA to meet their need and driving up costs for customers. As noted in the ALJ Ruling, CCSA "defines the generation capacity value as 'compensating community solar plus storage for reductions in the amount of generation capacity needed to support reliability'" and "proposes that the generation capacity component of the value stack will be 'derived from the hourly [ACC] Generation Capacity Costs.'"[32] However, this value only appears if the resource is considered load modifying and included in the California Energy Commission's ("CEC's") annual load forecast. As noted by SCE, FTM generation does not modify load and, therefore, does not provide the benefits assumed in the ACC associated with the avoidance of generation capacity costs.[33]

The Joint CCAs appreciate proposals to "establish appropriate controls to ensure that resources...would be dispatched to reduce ratepayer cost and support grid reliability," but are

---

31 *See* Opening Comments of Southern California Edison Company (U 338-E) on Administrative Law Judge's Ruling Setting Aside Submission of the Record to Seek Comments on Cost-Effectiveness Considerations ("SCE Cost Effectiveness Opening Comments") at 4 ("SCE has significant concerns about using the Integrated Distributed Energy Resources (IDER) ACC to quantify the "avoided cost" benefit of [FTM] GAP proposals because several of the costs included in the ACC are not avoided by these proposals as they do ***not*** modify load."); *see also* Opening Comments of Pacific Gas and Electric Company (U 39 E) in Response to Administrative Law Judge's Ruling Setting Aside Submission of the Record to Seek Comments on Cost-Effectiveness Considerations at 3, SCE Cost Effectiveness Reply Comments at 3.

32 ALJ Ruling at 4.

33 SCE Cost Effectiveness Reply Comments at 5.

concerned that they are not feasible to implement for the proposal in its current form. For example, as a threshold issue, the Joint CCAs understand that NVBT resources are not required to undergo deliverability studies. Without undergoing deliverability studies, it is uncertain if NVBT resources will even be able to be dispatched. If there are no siting restrictions on the projects, a payment which assumes delivery to the grid for a project which might be located in a constrained area, and therefore unable to deliver to the grid, is problematic.

Additionally, while the Joint CCAs appreciate the proposal of The Utility Reform Network ("TURN") to ensure that the LSE "be provided with limited storage dispatch rights" for NVBT resources, the Joint CCAs understand that NVBT facility owners explicitly do not enter into contracts with LSEs to provide power from their resources. Given this, the Joint CCAs do not understand what mechanism could be used to guarantee storage dispatch rights for the LSE and believe further details and guidance would be necessary before considering the TURN proposal.

Therefore, the Joint CCAs do not believe NVBT resources should universally receive the "full ACC avoided generation compensation based on long-term marginal costs." To do so could overvalue the resources due to the lack of certain reliability benefits and avoided transmission and distribution costs.

IV. THE COMMISSION MUST MAKE CONSISTENT DETERMINATIONS FOR ALL RESOURCES TO AVOID UNCERTAINTY IN DISTRIBUTED ENERGY RESOURCE POLICY

The Joint CCAs are concerned that certain questions contained in the ALJ Ruling invite specific determinations for the NVBT proposal which contradict or circumvent prior Commission guidance, and/or make determinations which could be reversed in the future.

Specifically, the Joint CCAs urge the Commission to ensure consistent determinations for all resources, including the NVBT, with regards to RA, and Rule 21 Interconnection issues.

a. Response to ALJ Ruling Question 4

As noted in the ALJ Ruling, the RA proceeding has rejected proposals to value BTM resources similarly to FTM resources for RA purposes.[34] However, ALJ Ruling Question 4 goes on to request that parties speculate as to how NVBT resources, if they are considered BTM resources, address the eight issues raised in that proceeding.[35] The Joint CCAs urge the Commission to be cautious about making specific RA-related determinations for the NVBT proposal in this proceeding given (i) that these issues have been previously raised in prior Commission decisions; and (ii) that there are currently two open proceedings addressing RA issues that provide venues to ensure a consistent approach to resources.[36] As the Commission transitions to implementing the Slice of Day framework, it is important that any questions or proposals surrounding NVBT that implicate RA issues be fully vetted and considered by the Commission to avoid the risk of not properly accounting for RA resources or creating confusion in the market on RA counting, compensation, and compliance. For example, in Commission Decision 20-06-031, the Commission noted that addressing the eight issues raised would "require consideration and coordination in multiple Commission proceedings and [California Independent System Operator ("CAISO")] stakeholder initiatives."[37] Additionally, the Commission presented those eight issues to highlight the "numerous issues [that] must be addressed before considering treating BTM resources similarly to [FTM] resources."[38] These

---

34 Decision ("D.") 20-06-031.
35 ALJ Ruling Attachment 1, Question 4(a).
36 R.21-10-002, which was reopened, and R.23-10-011, the newly issued Order Instituting Rulemaking initiating the successor rulemaking for the RA program.
37 D.20-06-031 at 33.
38 *Id.*

questions and issues should not be addressed on a project by project, or program by program basis, but rather consistently for a category of resources as part of the overall consideration of BTM resources for RA purposes.

An attempt to address these issues specifically for the NVBT resources, without the necessary coordination with the newly opened RA proceeding, may result in conflicting Commission decisions down the line. In other words, the Commission may be faced with a decision in the RA proceeding which directly conflicts with, and rejects, a proposed solution for NVBT resources approved as part of this proceeding.

Additionally, the Joint CCAs appreciate the Commission raising the issue of assuming full reliability value for load modifying resources which may not be fully reflected under the CEC annual load forecast due to uncertainty. The Joint CCAs share this concern. To the extent load modifying resources are not counted in the CEC's annual load forecast, they offer no RA value to the LSE and therefore should not be compensated for that value. The Joint CCAs understand that the CEC makes the final determination of whether the resources will be included in the load forecast. The Joint CCAs are concerned that if a determination is made about the reliability value for NVBT resources here it may result in overcompensating the resource for reliability. This is because the CEC may determine a lower value for those resources in the demand forecast, and thus the Commission's assumption about the reliability value may not actually materialize. Therefore, LSEs could face a situation where these resources, per the Commission's decision, are compensated for providing RA value as load modifying resources while the CEC refuses to accept such resources in its annual load forecast therefore denying LSEs any actual RA value for the resource.

b. Response to ALJ Ruling Question 9

The ALJ Ruling further requests speculation on the potential for interconnection of multiple generating systems leading to "upstream" transmission level issues and concerns, and whether Rule 21 is appropriate for potential NVBT FTM resources.[39]

The IOU Rule 21 tariffs were primarily designed to interconnect net energy metering ("NEM") systems that offset on-site load, non-exporting systems, and qualifying facilities selling power to the utility at avoided cost as defined by the Public Utility Regulatory Policies Act.[40] Facilities seeking to interconnect to the distribution system and provide wholesale energy and capacity services to the CAISO typically apply under the IOUs' Federal Energy Regulatory Commission-jurisdictional Wholesale Distribution Access Tariffs ("WDAT").[41] Each WDAT has its own generator interconnection procedures that require certain study processes in which the IOU conducts the necessary interconnection studies to identify upstream impacts and potential upgrades, as well as any deliverability assessments needed in accordance with the CAISO Tariff.[42] If NVBT FTM projects connect under Rule 21 or are fast-tracked outside the current rules, the necessary study or deliverability assessments must also be conducted, otherwise there could be safety concerns and adverse impacts to the system upstream. Given the current challenges of building the necessary assets required for connecting both new customer load and generating facilities to bring additional capacity online, the interconnection of multiple

---

[39] ALJ Ruling Attachment 1, Question 9.

[40] *See* R. 17-07-077, Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21 at 2; D.13-05-034 at 24.

[41] *Id.*; *see also* PG&E's Wholesale Distribution Tariff, Section 1.2, SCE's Wholesale Distribution Access Tariff, Section 1.2; and SDG&E's Open Access Distribution Tariff, Section 1.2.

[42] *See i.e.*, SCE's Wholesale Distribution Access Tariff's Attachment I Generator Interconnection Procedures ("GIP").

NVBT FTM systems at distribution must be carefully considered so that the appropriate assessments are made to account for any potential distribution and transmission upgrades and to ensure the proper buildout and overall safety of the grid.

As similarly noted in comments above for the RA program rules and by SCE in its rebuttal testimony,[43] any changes to interconnection rules and requirements should be noticed and considered by interested parties and the Commission before modifying tariff requirements in favor of one type of project or program. NVBT projects, therefore, should be properly identified as FTM, planned to be integrated into the CAISO market, and interconnected under the appropriate interconnection requirements currently in place.

V. CONCLUSION

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

November 27, 2023

Respectfully Submitted,

/s/ Brittany Iles

Brittany Iles
BRAUN BLAISING & WYNNE, P.C.
555 Capitol Mall, Suite 570
Sacramento, California 95814
Telephone: (916) 326-5812
E-mail: iles@braunlegal.com

Attorney for the
Joint Community Choice Aggregators and
City and County of San Francisco

---

[43] *See* Exhibit SCE-03: Rebuttal Testimony of Southern California Edison Company (U 338-E) in Support of Application for Review of the Disadvantaged Communities – Green Tariff (DAC-GT), Community Solar Green Tariff (CSGT"), and Green Tariff Shared Renewables (GTSR) Programs at 40-42.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027	Application 22-05-002
And Related Matters.	Application 22-05-003 Application 22-05-004

JOINT COMMUNITY CHOICE AGGREGATORS' OPENING COMMENTS ON THE PROPOSED DECISION DIRECTING CERTAIN INVESTOR-OWNED UTILITIES' DEMAND RESPONSE PROGRAMS, PILOTS, AND BUDGETS FOR THE YEARS 2024-2027

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

November 28, 2023

On behalf of the Joint Community Choice Aggregators

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Commission Rules of Practice and Procedure

SUMMARY OF RECOMMENDATIONS

- The Commission should clarify that all investor-owned utilities (IOU), and not just Pacific Gas and Electric Company (PG&E), must share data regarding customer enrollments in the Emergency Load Reduction Program (ELRP) with community choice aggregators (CCA) requesting such information.
- The Commission should require the IOUs initiate data sharing with CCAs for the purposes of facilitating load forecasting and dual enrollment prevention no later than June 1, 2024.
- The Commission should require the IOUs share enrollment information of CCA customers enrolled in all ELRP sub-groups.
- In addition to requiring the IOUs share customers' service agreement identification number (SAID), name and site address, the Commission should also direct IOUs to share customers' forecasted load reductions to facilitate CCAs' load forecasting efforts.
- The Commission should clarify the venue in which parties should bring proposed revisions to the dual participation rules.
- The Commission should adopt the Joint Community Choice Aggregators' (Joint CCAs) proposed modifications to the definition of a "qualified demand response program" and direct IOUs to coordinate with CCAs before filing Tier 2 advice letters to establish the eligible programs list.
- The Commission should clarify that customers receiving an incentive through the Self Generation Incentive Program Heat Pump Water Heater Program may participate in any qualified demand response program, and are not limited to participating in San Diego Gas and Electric Company's (SDG&E) market-integrated demand response programs.
- The Commission should adopt the Joint CCAs' recommended findings of fact, conclusions of law and ordering paragraphs included in Appendix A to these comments.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027	Application 22-05-002
And Related Matters.	Application 22-05-003 Application 22-05-004

JOINT COMMUNITY CHOICE AGGREGATORS' OPENING COMMENTS ON THE PROPOSED DECISION DIRECTING CERTAIN INVESTOR-OWNED UTILITIES' DEMAND RESPONSE PROGRAMS, PILOTS, AND BUDGETS FOR THE YEARS 2024-2027

The Joint Community Choice Aggregators[1] (Joint CCAs) submit these comments on the *Proposed Decision Directing Certain Investor-Owned Utilities' Demand Response Programs, Pilots, and Budgets for the Years 2024-2027* pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission and the Administrative Law Judge's November 22 Email Ruling Granting Extension of Time for Opening and Reply Comments for Phase II DR Proposed Decision.

The Joint CCAs appreciate the Administrative Law Judge's considerable efforts in crafting a reasoned Proposed Decision (PD) that addresses a range of complicated issues associated with the investor-owned utilities' (IOU) demand response (DR) portfolios and impacting the State's broader DR market. The Joint CCAs largely support the PD and recommend the following revisions to strengthen and clarify its findings, conclusions, and directives.

[1] The Joint CCAs consist of East Bay Community Energy (now "Ava Community Energy"), Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), the City of San José – which operates and administers San José Clean Energy (SJCE) through the City's Community Energy Department, and Sonoma Clean Power Authority (SCP).

First, while the Joint CCAs applaud the PD for directing Pacific Gas and Electric Company (PG&E) to share Emergency Load Reduction Program (ELRP) customer enrollment information with community choice aggregators (CCAs) to facilitate dual enrollment prevention and load forecasting,[2] the Joint CCAs recommend the Order make a series of narrow modifications to strengthen the PD's conclusions on this issue. Those modifications include: (1) clarifying that all IOUs, and not just PG&E, must share customer enrollment information with CCAs in their respective territories requesting such information; (2) establishing a specific timeline by which the IOUs must complete data sharing; (3) extending the data sharing requirement beyond ELRP sub-groups A.1 and A.6 to all sub-groups; and (4) directing the IOUs to share data regarding customers' forecasted load reductions to facilitate CCAs' load forecasting efforts.

Second, the Joint CCAs recommend three minor modifications to the PD to promote clarity and avoid unnecessary litigation or confusion in future proceedings:

- **Dual Enrollment:** While the Joint CCAs continue to believe that the dual participation rules require the Commission's attention, the Joint CCAs agree parties "could work together to hold their own workshops and provide a proposal for changes" to the dual participation rules, as the PD advises.[3] The Commission should, however, clarify the "Commission venue" where parties might bring such a proposal.

- **Definition of Qualified DR Programs and Process for Establishing Eligible Program List:** The Commission should adopt the Joint CCAs' recommended clarifying modifications to the PD's proposed definition of a "qualified demand response program" for the purposes of eligibility to meet a DR program enrollment requirement and direct the IOUs to coordinate with CCAs before filing a list of eligible programs.

- **Heat Pump Water Heater Program Enrollment (SDG&E):** The Commission should clarify that customers participating in the Self Generation Incentive Program (SGIP) Heat Pump Water Heater (HPWH) Program may enroll in *any* eligible DR program and are not limited to enrolling only in San Diego Gas & Electric Company's (SDG&E) supply-side DR programs.

---

2 PD at 177-179.

3 *Id.* at 20.

Appendix A to these comments lists the Joint CCAs' recommended modifications to the PD's findings of fact (FOF), conclusions of law (COL) and ordering paragraphs (OP). The Joint CCAs request the Commission adopt those recommended modifications for the reasons described in these comments.

I. THE PD REQUIRES REVISIONS TO STRENGTHEN ITS DATA-SHARING DIRECTIVES.

In this proceeding, the Joint CCAs have focused on advocating for a transparent, streamlined data exchange process to facilitate dual enrollment prevention and load-serving entity (LSE) load forecasting. The PD correctly acknowledges the importance of data exchange for both load forecasting and dual enrollment prevention purposes and directs PG&E to share ELRP customer enrollment information with CCAs.[4] While the Joint CCAs generally support the PD's conclusions on this issue, the Joint CCAs recommend four modifications to strengthen its directives. First, the Order should clarify that all IOUs—and not just PG&E—must share customer enrollment information with CCAs in their respective service territories upon request. Second, the Order should direct the IOUs to complete this initial data exchange no later than June 1, 2024. Third, the Commission should expand its data-sharing directive to all ELRP sub-groups. Fourth, the Commission should direct the IOUs to share customers' forecasted load reduction data (either on a per customer or aggregate basis) in order to facilitate the CCAs' load forecasting efforts. The Joint CCAs discuss each of these modifications below.

A. The Commission Should Direct all IOUs, and Not Just PG&E, to Share Data with CCAs.

The PD directs PG&E to "share enrollment information of CCA customers enrolled in PG&E's ELRP sub-groups A.1 and A.6 with the CCAs requesting such information for their

---

[4] *Id*. at 177-179.

customers, for the purposes of CCA load forecasting and resolving potential dual enrollment issues between ELRP and programs managed by the CCAs."[5] The Commission should consistently apply this directive and require both Southern California Edison (SCE) and SDG&E to share DR program customer enrollment information with the CCAs in their service territory upon request. The Joint CCAs focused on PG&E in their testimony and briefs because each of their constituent CCAs is located in PG&E's service territory; however, CCAs administering load-modifying DR programs in SCE's and SDG&E's service territories would equally benefit from a streamlined data sharing process to facilitate their dual enrollment prevention and load forecasting efforts. Importantly, a broader directive would ensure all three IOUs share data with CCAs in a consistent manner, replacing the current patchwork of practices across service territories.

B. The Commission Should Direct the IOUs to Initiate Data Sharing No Later than June 1, 2024.

While the PD directs PG&E to share customer enrollment information with CCAs, it does not establish a specific timeline for PG&E to do so. This creates the risk that PG&E will not deliver data in a timely fashion, extending the dual enrollment prevention challenges that CCAs currently face into the 2024 summer season. To avoid this unnecessary outcome, the Commission should direct PG&E (and the other IOUs) to complete the implementation of a data sharing process no later than June 1, 2024, in time for the 2024 summer season. That timeline should not be unduly burdensome for PG&E (or any IOU), because the data sharing contemplated by the PD does not require a sophisticated technology solution; it requires only that the IOU share a spreadsheet including a small number of data points with CCAs.

[5] *Id*. at 179.

C. The Commission Should Extend the Data Sharing Requirement to All ELRP Sub-Groups.

The PD directs PG&E to share enrollment information of CCA customers enrolled in PG&E's ELRP sub-groups A.1 and A.6, but does not adopt a similar data-sharing requirement for the remaining ELRP sub-groups. The PD does not explain why its directive is limited to sub-groups A.1 and A.6. The Commission should either explain why its directive is limited to those sub-groups or expand that directive to all ELRP sub-groups. By requiring the IOUs to share data related to customers participating in sub-groups A.2 through A.5, the Commission can help ensure those ratepayer-funded programs do not result in "double-counting" to the detriment of both ratepayers and the State's policy goals.

PG&E has argued that the utility cannot share information related to certain ELRP sub-programs "without fostering or participating in an anti-competitive market[.]"[6] To the extent that PG&E's concern impacts the breadth of the PD's directive, the Joint CCAs note that—by the terms of the PD itself—customer enrollment data would be used for dual enrollment prevention and load forecasting only, and not for marketing or other competitive purposes. To further mitigate PG&E's concern, the Commission could direct third-party aggregators to submit data directly to CCAs, rather than requiring that data be transferred to the CCAs through the IOU.

D. The Commission Should Direct IOUs to Share Forecasted Load Reduction Data to Facilitate CCAs' Load Forecasting Efforts.

The PD directs data sharing for two purposes: CCA load forecasting and resolving potential dual enrollment issues between ELRP and programs managed by the CCAs.[7] To that end, the PD directs PG&E to share basic customer information including service agreement identification number (SAID); customer name; and site address. While those data points are essential for

---

6 PG&E Reply Brief at 5.

7 PD at 179.

facilitating dual enrollment prevention, CCAs' load forecasting efforts require customers' forecasted load reductions (either load reduction per customer, or aggregated) resulting from their participation in DR programs. CCAs cannot incorporate the impacts of their customers' participation in DR programs into their load forecasting efforts based only on customer SAID, name and site address. The Commission should therefore include customers' forecasted load reductions in the list of data that IOUs must share with CCAs to facilitate load forecasting and dual enrollment prevention efforts.

II. THE PD REQUIRES MODEST REVISIONS TO IMPROVE CLARITY AND AVOID UNNECESSARY LITIGATION AND CONFUSION IN FUTURE PROCEEDINGS.

A. The Commission Should Clarify the Appropriate Venue for Parties to Bring Proposals Seeking to Update the Dual Participation Rules.

Several parties to this proceeding, including the Joint CCAs, supported dual participation workshops to revisit the dual participation rules. The PD, however, declines to direct workshops on this issue.[8] The Joint CCAs do not object to the Administrative Law Judge's decision not to direct dual participation workshops, but continue to believe that the dual participation rules deserve the Commission's attention. Dual participation between traditional (event-based) DR programs and daily load-shifting rates and programs will become an increasingly significant issue in the near future.

For example, distributed energy resources (DER) enrolled in either a supply-side DR program or a direct load control load-modifying program must be registered with a Distributed Energy Resource Management System (DERMS) platform for control and dispatch. If a DER is dually enrolled in an event-based DR and a daily load shifting program (a scenario, that is not categorically prohibited under the current dual enrollment rules), and the two programs are

---

[8] *Id*. at 20.

managed by different DERMS, then the device original equipment manufacturer (OEM) must de-conflict competing dispatch signals, a function the device may not be set up to do. As another example of the issues that dual enrollment in an event-based and a daily load shifting program can create, daily load shifting programs can reshape the underlying baseline profile of a customer's load, which might degrade the event-based load shed value of a dually-enrolled asset.

The Joint CCAs provide these examples to illustrate the complexity of the State's evolving DR landscape and emphasize the importance of revisiting the outdated dual participation rules. Nevertheless, Joint CCAs agree "relevant parties could work together to hold their own workshops and provide a proposal for changes" to the dual participation rules, as the PD advises.[9] The PD further suggests parties could provide such a proposal at "the next appropriate Commission venue."[10] The Joint CCAs request the Commission clarify "the next appropriate Commission venue" (e.g., which would be the appropriate Commission proceeding) to aid the efforts of the CCAs and other parties interested in developing such a proposal.

B. The Commission Should Modify the Definition of a "Qualified Demand Response Program" and Direct IOUs to Coordinate with CCAs Before Filing a List of Eligible Programs.

The PD adopts the following definition of a "qualified DR program" to satisfy a potential DR enrollment requirement established by the Commission:

---

9 *Id.*

10 *Id.*

1. Supply-side market integrated DR programs counted for RA irrespective of whether the administrator is an IOU, CCA, or third-party DRP.

2. Load modifying DR programs that meet the following two requirements:

    a. The program is integrated with the CAISO energy market such that the program's dispatch signal is linked to the energy prices in the Day-ahead or real-time market – operational domain.

    b. The program's load impact is counted towards RA obligations either directly or indirectly through a Commission-approved process or planning domain.

3. Any DR pilot authorized and designated by the Commission as a "qualified" DR program.

4. Critical Peak Pricing or Peak Day Pricing. These options shall be discontinued as a "qualified" DR program when the dynamic rate(s) under consideration in R.22-07-005 is (are) made available to customers that is (are) compliant with CEC Adopted Load Management Standards (California Code of Regulations – Title 20, Article 5, § 1623).

While the Joint CCAs largely support this definition, the Joint CCAs recommend four narrow changes.

First, the Commission should clarify that all programs falling on this list, and not just market-integrated DR programs, are eligible whether administered by an IOU, CCA, or third-party demand response provider (DRP). The Commission can accomplish this objective by adding the following language prior to the four categories of eligible programs (and striking the corresponding language from Category 1): "<u>The following DR programs are deemed as "qualified" to satisfy a potential DR enrollment requirement established by the Commission for an authorized program irrespective of whether the administrator is an IOU, CCA, or third-party DRP</u>."

Second, rather than narrowly limiting load-modifying programs to those relying directly on CAISO energy market price signals, the Commission should allow programs that contribute to reliability (*i.e.*, those where the DR incentive is objectively related to reliability) to qualify as eligible programs. The Commission can allow this flexibility by changing the language of category

2.a. to the following: "The program is operated in a manner that supports grid reliability, either through CAISO market integration (e.g., via a dispatch signal), system or LSE forecasted peak-based dispatch, rate-based dispatch (e.g., MIDAS or other rate optimization signal), or based on avoided cost values (e.g. the Commission's Avoided Cost Calculator (ACC))."

Third, the Joint CCAs note that the dynamic rates listed under category 4 are daily load-shifting strategies, rather than a traditional event-based DR approach. It is therefore inconsistent to include dynamic rates as qualified DR programs under category 4 unless the Commission also incorporates daily load-shifting programs under the load-modifying programs described in category 2. The Commission can reconcile this inconsistency by either removing category 4, or by adding the following language to the beginning of category 2: "Event-based or daily load-shifting load modifying DR programs. . ."

Finally, whereas the PD states, in dicta, that IOUs and LSEs may submit a Tier 2 advice letter to update the eligible program list on an as needed basis,[11] OP 10 directs only the IOUs to submit Tier 2 advice letters within 60 days of the Decision to establish and update the eligible programs list.[12] The Commission should reconcile the dicta and OP by clarifying that IOUs must coordinate with CCAs and other LSEs before submitting Tier 2 advice letters establishing the initial eligible programs list; that the eligible programs list must include all eligible CCA programs; and that once the initial eligible programs list is established, all LSEs may submit Tier 2 advice letters to make updates to that list. The Commission can achieve this objective by adding the following language to Ordering Paragraph 10: "Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company are each directed to coordinate with CCAs in their service territories and submit Tier 2 advice letters within 60 days

[11] *Id*. at 25.
[12] *Id.* at Ordering Paragraph 10.

of the issuance date of this decision to establish ~~and update~~ the eligible programs list for the purposes of determining what a "qualified Demand Response (DR) program is in order to satisfy DR incentive conditions. The eligible program list must include all eligible CCA programs in the IOU's service territory. Any LSE may file a Tier 2 Advice Letter following the establishment of the eligible program list in order to update that list."

In sum, the Joint CCAs propose the following changes to the definition of "qualified DR program" included in Attachment 1:

The following DR programs are deemed as "qualified" to satisfy a potential DR enrollment requirement established by the Commission for an authorized program irrespective of whether the administrator is an IOU, CCA, or third-party DRP.

~~1.~~ Supply-side market integrated DR programs counted for RA ~~irrespective of whether the administrator is an IOU, CCA, or third-party DRP.~~

2. Event-based or daily load-shifting l~~L~~oad modifying DR programs that meet the following two requirements:

   a. ~~The program is integrated with the CAISO energy market such that the program's dispatch signal is linked to the energy prices in the Day-ahead or real-time market – operational domain.~~ The program is operated in a manner that supports grid reliability, either through CAISO market integration (e.g., via a dispatch signal), system or LSE forecasted peak-based dispatch, rate-based dispatch (e.g., MIDAS or other rate optimization signal), or based on avoided cost values (e.g. the Commission's Avoided Cost Calculator (ACC)).

   b. The program's load impact is counted towards RA obligations either directly or indirectly through a Commission-approved process or planning domain.

3. Any DR pilot authorized and designated by the Commission as a "qualified" DR program.

4. Critical Peak Pricing or Peak Day Pricing. These options shall be discontinued as a "qualified" DR program when the dynamic rate(s) under consideration in R.22-07-005 is (are) made available to customers that is (are) compliant with CEC Adopted Load Management Standards (California Code of Regulations – Title 20, Article 5, § 1623).

C. The Commission Should Clarify that Customers Enrolling in the SGIP HPWH Program May Enroll in Any Qualified DR Program, and Are Not Limited to Enrolling in SDG&E's Supply-Side DR Programs.

SDG&E proposes to enroll customers that have received the SGIP HPWH incentive into SDG&E's supply-side DR programs;[13] however, the Joint CCAs understand customers may fulfill the SGIP HPWH DR enrollment requirement by choosing from a variety of DR programs, irrespective of whether the administrator is an IOU, CCA, or third-party DRP, consistent with the definition of a "qualified DR program" adopted in the PD.

The PD authorizes SDG&E to submit a Tier 2 advice letter to fund-shift to cover costs associated with incorporating HPWHs into its supply-side DR programs.[14] The Joint CCAs have no objection to the PD's conclusion. To avoid any confusion, however, the Joint CCAs recommend the Commission add language clarifying that customers receiving an SGIP HPWH incentive are not *required* to participate in SDG&E's supply-side DR programs, and may participate in any "qualified DR program" included in the list that SDG&E submits pursuant to Ordering Paragraph 10 of the PD.

III. CONCLUSION

The Joint CCAs appreciate the Administrative Law Judge's efforts in resolving the several complex issues in this proceeding. For the reasons described in these comments, the Joint CCAs respectfully request the Commission adopt the revisions discussed in these comments and detailed in Appendix A, attached hereto.

---

13 *Id*. at 25.
14 *Id.* at 25-26, Ordering Paragraph 11.

Respectfully submitted,

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

November 28, 2023

APPENDIX A

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, the Joint CCAs provide this Appendix setting forth proposed changes to the *Proposed Decision Directing Certain Investor-Owned Utilities' Demand Response Programs, Pilots and Budgets for the Years 2024-2027*, including proposed changes to the findings of fact, conclusions of law and ordering paragraphs. The Joint CCAs' proposed revisions appear in underline and strike-through.

Findings of Fact

X. The Joint CCAs presented compelling evidence that CCAs face issues with dual enrollment of customers in ELRP and their own load-modifying DR programs, and that such problem should be remedied when compared to existing Commission policy.

Conclusions of Law

X. The following DR programs are deemed as "qualified" to satisfy a potential DR enrollment requirement established by the Commission for an authorized program irrespective of whether the administrator is an IOU, CCA, or third-party DRP.

~~1.~~ Supply-side market integrated DR programs counted for RA.

2. Event-based or daily load-shifting load modifying DR programs that meet the following two requirements:

   a. The program is operated in a manner that supports grid reliability, either through CAISO market integration (e.g., via a dispatch signal), system or LSE forecasted peak-based dispatch, rate-based dispatch (e.g., MIDAS or other rate optimization signal), or based on avoided cost values (e.g. the Commission's Avoided Cost Calculator (ACC)).

   b. The program's load impact is counted towards RA obligations either directly or indirectly through a Commission-approved process or planning domain.

3. Any DR pilot authorized and designated by the Commission as a "qualified" DR program.

4. Critical Peak Pricing or Peak Day Pricing. These options shall be discontinued as a "qualified" DR program when the dynamic rate(s) under consideration in R.22-07-005 is (are) made available to customers that is (are) compliant with CEC Adopted Load Management Standards (California Code of Regulations – Title 20, Article 5, § 1623).

X. Customers in San Diego Gas & Electric Company's service territory receiving a Heat Pump Water Heater Program incentive may participate in either SDG&E's supply-side market-integrated DR programs or any other "qualified DR program" included on the list of eligible programs.

Ordering Paragraphs

10. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company are each directed to coordinate with CCAs in their service territories and submit Tier 2 advice letters within 60 days of the issuance date of this decision to establish ~~and update~~ the eligible programs list for the purposes of determining what a "qualified Demand Response (DR) program is in order to satisfy DR incentive conditions. The eligible program list must include all eligible CCA programs in the IOU's service territory. Any LSE may file a Tier 2 Advice Letter following the establishment of the eligible program list in order to update that list.

X. Beginning no later than June 1, 2024, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company are each directed to share enrollment information of CCA customers enrolled in the ELRP with the CCAs requesting such information for their customers, for the purposes of CCA load forecasting and resolving potential dual enrollment issues between ELRP and programs managed by the CCAs. Each IOU will share with the requesting CCA, at a minimum on a monthly basis, basic customer information including service agreement identification number, customer name, and site address, as well as forecasted load reductions (on a per customer or aggregate basis, as available).

California Community Choice Association

SUBMITTED 11/30/2023, 03:38 PM

Contact
Lauren Carr (lauren@cal-cca.org)

1. **What additional clarifications would be helpful from the CAISO that were not already covered in the November 8 workshop?**

   The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the California Independent System Operator's (CAISO) November 8, 2023, workshop on Slice-of-Day (SOD) near-term implementation. CalCCA's primary near-term concern is ensuring that if a load-serving entity (LSE) complies with SOD at the California Public Utilities Commission (CPUC), the LSE will also comply with the CAISO's resource adequacy (RA) program without the LSE having to take additional procurement actions. The CAISO should confirm whether LSEs will definitively meet CAISO RA requirements if they meet SOD requirements. If not, the CAISO should take additional steps to minimize the need for CPUC-jurisdictional LSEs to meet two different compliance obligations.

   As CalCCA understands the CAISO's proposed steps for validating RA showings under SOD, if LSEs meet CPUC SOD requirements, they will meet CAISO RA requirements in *most* instances. There could be situations when an LSE shows storage for less than four hours and more than its capacity at four-hour duration in which the storage would count for less at CAISO than it would at the CPUC. These situations have the potential of creating two compliance paradigms by only counting storage at its four-hour duration, when the CPUC would allow storage to count at durations less than four hours. The CAISO should work with the CPUC to develop a uniform minimum duration used in CAISO and CPUC processes so it is consistent between the two programs.

2. **Are there any gaps that have not been covered that result in a near-term compliance risk? Please elaborate on the issue and impact.**

   There are two gaps that have not been sufficiently addressed by CAISO:

   First, the way the CAISO proposes to require maximum import capability (MIC) is inconsistent with how import resources can be shown under SOD. The CAISO plans to require MIC for the amount of NQC shown in the one hour the CAISO will validate, regardless of whether the import is shown in that hour or not, or if the import is shown for more or less capacity in other hours. Requiring showings of MIC in this manner may under or over-utilize MIC. This is because, under the CPUC's SOD counting rules, non-resource specific imports can count in the hours specified in their contracts. If an LSE shows a solar import during the daylight hours and a gas resource in all 24 hours, assuming the solar resource is unavailable during the hour the CAISO validates, the CAISO would effectively only require MIC for the gas resource, even though both the solar and the gas would be shown for non-zero values during the daylight hours. Conversely, if an LSE shows two storage imports, one in the morning ramp and another in the evening ramp, the CAISO would require MIC that totals the net qualifying capacity (NQC) of the two storage resources, even though they do not overlap in any hour on the LSE's RA showing. The CAISO's planned MIC requirements under SOD will result in requiring more or less MIC than required to import out-of-state RA resources.

   Second, the CAISO provides very little information about how it will make capacity procurement mechanism (CPM) decisions under SOD. It indicates that it will CPM "[b]ased on shown RA (up to NQC value)." This level of detail is insufficient for a long-term solution to assessing the need for CPM and allocating CPM costs. The CAISO must discuss with stakeholders how it should conduct backstop once CPUC jurisdictional LSEs are subject to SOD and non-CPUC jurisdictional LSEs are not. Ensuring all local regulatory authorities (LRA) bring their share of RA capacity necessary to meet reliability needs in all hours will be an important consideration, especially considering the CAISO's responsibility to administer the different RA programs adopted by each LRA. LRAs have their own definitions, methods of measurement, and planning standards for their RA programs. Assuming the CAISO and non-CPUC LRAs do not shift to a SOD RA program like the CPUC has, the CAISO needs some other way to determine whether each of the different RA programs results in an RA fleet that is available when and where needed to meet reliability needs in all hours, not just the single hour the CAISO currently checks for compliance.

3. Does your organization have any additional feedback on 2025 Slice of Day Implementation related to CAISO processes?

CalCCA has no additional feedback at this time.