# Regulatory Packet

# Part 2

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

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| Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment. | Rulemaking 17-06-026 (Filed June 29, 2017) |

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS
IN RESPONSE TO STAFF'S ERRA TIMING PROPOSAL**

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*On behalf of*
California Community Choice Association

June 15, 2021

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Pursuant to Administrative Law Judge Wang's May 20, 2021 E-mail Ruling ("Ruling"),[1] the California Community Choice Association[2] ("CalCCA") submits the following opening comments on Energy Division Staff's proposal to revise the publication date for the Power Cost Indifference Adjustment ("PCIA") Market Price Benchmarks ("MPBs") from November 1 to October 1 of each year ("Staff Proposal").[3]

As discussed at the June 4, 2021 workshop ("Workshop"), the Staff Proposal can address the underlying problems with the ERRA forecast timelines, while improving community choice

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

2 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy Authority, 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, Silicon Valley Clean Energy Authority, Solana Energy Alliance, Sonoma Clean Power Authority, Valley Clean Energy, and Western Community Energy.

3 R.17-06-026, Energy Division Staff, *Revision of the of the Power Cost Indifference Adjustment Market Price Benchmarks calculation date from November 1 to October 1 of each year* (May 20, 2021) ("Staff Proposal").

aggregators' ("CCAs") and other parties' ability to effectively participate within the proceedings, if the Commission:

- Implements the Staff Proposal next year (*i.e.*, during the IOUs' 2023 ERRA forecast cases);
- Maintains the current, typical procedural schedules for the ERRA forecast proceedings that occur prior to each year's update;
- Requires SCE and PG&E to file their ERRA forecast applications on May 1 each year instead of June 1, or, at the very least, on a filing date in the first half of May; and
- Targets Q1 2022 implementation for this year's ERRA forecast proceedings, similar to SCE's request in its 2022 ERRA forecast application.

Moreover, adopting the Master Data Request ("MDR") approach for the SCE and SDG&E ERRA forecast proceedings that is currently utilized for the PG&E proceeding will increase the efficient resolution of these cases. The Commission wisely scoped this phase of this proceeding broadly to include consideration of this *entire* suite of solutions, and no petitions for modification are necessary to adopt them.

## I. STAFF'S PROPOSAL IS AN IMPORTANT PART OF A SUITE OF PROCEDURAL SOLUTIONS.

The numerous reasons Staff cited at the Workshop as support for revising the MPB publication dates are irrefutable,[4] with many having been raised by CCA parties in the utilities' individual ERRA forecast proceedings in recent years.[5] Moving the MPB publication from late October to late September, thereby replacing the "November Update" with an "October Update",

[4] R.17-06-026, *Commission Staff Presentation, Energy Division Workshop on the PCIA Market Price Benchmark Release Date*, slides 6, 8 (June 4, 2021).

[5] *See, e.g.,* A.19-06-001, *Protest of the Joint CCAs to the Application of Pacific Gas and Electric Company (U 39 E) for 2020 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast And Greenhouse Gas Forecast Revenue Return And Reconciliation*, pp. 26-29 (July 5, 2019).

will give the Commission and parties sufficient time to reach a reasoned decision, without the need to stipulate to shortened timelines, in time for January 1 implementation.

The substantive implications of this change, losing September balance-of-year transactions for RA and September RPS transactions in the Final MPBs appear to be minimal. The low RA transactional volumes in September for October through December of the same year appear unlikely to have a substantial impact on the final benchmarks. For RPS, September does not appear to be a particularly robust month. During the Workshop, Energy Division suggested it may conduct an analysis to determine the impact of removing September from the Final MPB over the past few years, *i.e.*, studying how the MPBs would have changed if the Staff Proposal had been adopted during those years. Such a Commission-sponsored analysis of these impacts to verify parties' understanding may be prudent, especially if the Commission adopts, but does not implement, the Staff Proposal this year.

In terms of the Forecast MPBs, the "missing" September data would be picked up on a going-forward basis in the following year's benchmark. Thus, while the accuracy of the MPBs could be reduced to some extent because market data for September will not be included in the MPB until the following year, or in the case of the Final MPBs will be excluded altogether, such concerns do not override the benefits of moving up the benchmark calculation.

The procedural questions surrounding the Staff Proposal are more concerning, however, and it will be important to avoid trading one set of procedural problems for another set of problems. If it adopts the Staff Proposal, the Commission can and should address these issues comprehensively as part of this case, including moving the filing dates for PG&E and SCE's applications up by one month, or at least a few weeks, and requiring the same MDR approach for all three IOUs.

### A. The Staff Proposal is Helpful But Incomplete.

The CCAs' underlying issue for the ERRA forecast proceedings has been, and continues to be, the compression of the cases' procedural schedules. While CalCCA proposed moving the November Update timeline up one week as part of its comments in January, the CCAs did not support moving it up a full month. As stated in those comments, in general, the problems with the November Update "have not been a function of MPB timing."[6]

CalCCA is agnostic as to whether relief to schedule compression comes at the beginning of the case or at the back end of the case. As discussed in more detail below, the Staff Proposal makes sense as long as other procedural adjustments are made. In the alternative, CalCCA continues to support a March 1 implementation date,[7] which will give the Commission and parties adequate time to review, analyze workpapers, conduct discovery on, and draft comments addressing the November update.[8] The bottom line is that, presently, there is insufficient time to fully vet each part of the ERRA forecast cases. If the ultimate resolution the Commission reaches is to shift some of the schedule compression from one part of the proceeding to another, such a resolution would fail to address the CCAs' underlying concerns.

### B. Revisions to the MPB Publication Date Should Avoid Trading One Set of Procedural Problems for Another.

The Staff Proposal should be adopted only if the PG&E and SCE application dates move forward, allowing the existing procedural timelines between the application date and reply briefs

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6 R.17-06-026, *California Community Choice Association's Comments on Assigned Commissioner's Amended Scoping Memo and Ruling*, p. 24 (Jan. 22, 2021).

7 R.17-06-026, *Joint Response of Southern California Edison Company (U 338-E), San Diego Gas & Electric Company (U 902 E) and Pacific Gas and Electric Company (U 39 E) to Assigned Commissioner's Amended Scoping Memo and Ruling*, p. 15 (Jan. 22, 2021).

8 R.17-06-026, *California Community Choice Association's Reply Comments on Assigned Commissioner's Amended Scoping Memo and Ruling*, p. 4 (Feb. 5, 2021).

to be kept. Generally speaking, the process could follow a schedule similar to the following, with the major milestones highlighted in blue:

| Date | Procedural Step |
|---|---|
| April 15 | SDG&E files its Application[9] |
| May 1 | PG&E and SCE file their Applications |
| Early June | Protests to Applications due |
| Mid-June | Replies to Protests due and Prehearing Conference |
| Late June/Early July | Scoping Ruling published |
| Early August | Intervenor testimony due |
| Mid-August | Rebuttal testimony due |
| Late August | Hearings |
| Mid-September | Opening briefs due |
| Late September | Reply briefs due |
| End of September | Energy Division publishes the MPBs |
| Early October | Updates filed |
| Late October | Comments on updates filed |
| Mid-November | Proposed Decision issued |
| Last Commission Business Meeting in December | Decision adopted |
| January 1 | Rates implemented |

[9] The SDG&E procedural dates do not need to shift to accommodate Staff's Proposal. Thus, the dates in this table between May 1 and the "End of September" only apply to PG&E and SCE's cases.

While the judges for each ERRA forecast proceeding will ultimately decide the specific schedule for each case, providing broad guidance targeting the schedule above will accomplish the goals in the Staff Proposal without causing collateral procedural problems.

Failing to undertake this type of comprehensive revision to the ERRA forecast process, while still adopting the Staff Proposal, will cause problems in October of each year and beyond. For example, the typical procedural schedules for SCE and PG&E's ERRA forecasts utilize October for some combination of testimony, hearings, and briefing.[10] Simply moving the update forward one month will result in witnesses responsible for testimony and hearings concurrently working on (a) testimony and hearings and (b) either "October Update" testimony or comments responding to that testimony. Facts on which those witnesses may be testifying will be changing simultaneously with the publication of the updates. Discovery on the updates will coincide with discovery in preparation for hearing. Briefs will need to be written concurrently with comments or somehow incorporate those comments. Judges and staff will need to analyze these various components of the record at the same time rather than in the type of sequential order that might allow for drafting of Proposed Decisions on some issues while issues related to the updates are still pending. The intense administrative burdens on Staff, judges, witnesses, and attorneys currently felt in November and December will simply switch to intensive burdens in October and November.

To avoid this result, it will be important to move the rest of the procedural schedule forward in addition to the publication of the MPBs. Implicit in the timelines between procedural steps in the table above, this approach allows parties and the Commission to complete the record

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[10] *See, e.g.,* A.20-07-004, *Assigned Commissioner's Scoping Memo and Ruling*, p. 4 (Sept. 10, 2020); A.19-06-002, *Assigned Commissioner's Scoping Memo and Ruling*, p. 4 (Aug. 22, 2019); and A.20-07-002, *Assigned Commissioner's Scoping Memo and Ruling*, pp. 4-5 (Sept. 10, 2020).

on any issues unrelated to the update prior to the update being published. This staggering of issues has allowed for efficient resolution of certain issues in these proceedings over the past few years, and that efficiency is one successful part of the current process that should not be altered.

Concurrently, it is critical the Commission maintain the current amount of time that exists in each proceeding prior to the update being filed. Shifting each aspect of the proceeding up by one month, while maintaining the current filing dates, will squeeze the beginning of the proceeding in untenable ways. The key problems here are two-fold: (1) the effect on the timing of protests, responses, prehearing conferences, scoping rulings and direct testimony and (2) the corresponding ability for intervenors to effectively prosecute these cases.

PG&E and SCE both file June 1, with protests due the first week in July. For example, protests for this year's proceedings are due July 6 and July 12, respectively, with the IOUs' replies due July 16 and July 22. If the rest of the schedule shifts forward by a month, there would be only 2-4 weeks between the due date for replies and intervenor testimony, leaving a short amount of time for the Commission to hold a prehearing conference and issue a Scoping Ruling. Despite it occurring the past few years, it is deeply unfair to expect parties to draft testimony within a week or two of the issuance of a Scoping Ruling, especially in cases where disputes over scope are not uncommon,[11] and parties may not know if certain issues can be raised in testimony.

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[11] *See, e.g.*, A.13-05-015, *Scoping Memo and Ruling of Assigned Commissioner*, p. 4 (Sept. 12, 2013) (rejecting the inclusion of certain issues in scope and finding that policy issues and other industry-wide practices such as changes to the PCIA methodology are properly addressed in rulemaking dockets, such as R.17-06-026); A.17-06-005, *Scoping Memo and Ruling of Assigned Commissioner,* pp. 3-4 (Aug. 24, 2017) (finding certain issues raised in protests would constitute changes to existing methods of calculation and not allegations of non-compliance with Commission rules, decisions, and resolutions on the part of PG&E); A.18-06-001, *PG&E Reply to Protests and Responses*, pp. 2-3 (July 16, 2018) (arguing issues the Joint CCAs raised in their Protest issue are out of scope, including that "challenges to the Commission's existing policy and/or rules are beyond the scope of this proceeding and must be raised via a petition for modification of the decision that established the policy and/or rule in question.").

Exacerbating these procedural questions is the fact that a substantial amount of work is done in these proceedings prior to the updates, including ratemaking, policy and implementation work the Commission has punted to these cases from other cases, including prior ERRA forecast cases. Examples of these issues in just the past few years include:

For PG&E:
- The methodology to refund a Cost Allocation Mechanism ("CAM") misallocation;[12]
- The methodology to return ERRA overcollections in an equitable manner;[13] and
- The methodology to calculate the RA component of GTSR rates.[14]

For SDG&E:
- The right billing determinants to reflect departing load when setting 2021 rates;[15] and
- Questions regarding the correct rate to form the basis for the PCIA rate cap.[16]

All three IOUs:
- Implementation of changes to the methodology used to calculate the PCIA from D.18-10-019 and D.19-10-001;[17]
- Questions surrounding funding for the Solar on Multi-family Affordable Housing program;[18] and
- Issues related to transparency and data access.[19]

It is unlikely the need to resolve ratemaking, policy and implementation issues will diminish. This year, the parties to PG&E's ERRA forecast case will need to address the accounting treatment for PG&E's "emergency" Green Tariff Shared Renewables ("GTSR") Petition for Modification ("PFM"), if is granted,[20] the utility's inclusion of unapproved

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12 D.20-02-047 at 10.

13 *Id*. at 11-12.

14 D.20-12-038 at 28-29.

15 D.21-01-017 at 42-44.

16 *Id*. at 34-38.

17 *See, e.g.,* D.18-10-019 at Ordering Paragraphs ("OPs") 8 and 10; D.19-10-001 at OPs 2-4.

18 *See* D.17-12-022 at OP 4.

19 D.20-12-035 at OP 8; D.20-12-038 at OP 4; D.21-01-017 at OP 6.

20 *See* A.12-04-020, PG&E Response to City and County of San Francisco Data Request 9.2(a)

Catastrophic Event Memorandum Account and Wildfire Expense Memorandum Account costs in the PCIA revenue requirement,[21] and the utility's proposal to shift certain Public Purpose Program ("PPP")-related costs out of the un-vintaged PCIA and into the PPP.[22]

This proceeding will continue to modify the PCIA methodology, and other Commission decisions will continue to impact the forecast cases. For example, since no two parties read a Commission decision the same way, implementation of the Voluntary Allocation and Market Offer component of the Commission's Working Group 3 decision, D.21-05-030, is likely to introduce new implementation issues for the 2023 ERRA forecast case. In addition, recent RA decisions are almost certain to introduce new accounting issues to both the 2022 and 2023 ERRA forecast proceedings, *e.g.*, ensuring that if existing resources are procured by the Central Procurement Entity (D.20-06-002), to meet 2021 summer reliability targets (D.21-02-028), or to meet the incremental procurement targets 2021-2023 (D.19-11-016), they are accounted for correctly in the CAM balancing accounts, mod-CAM balancing accounts and the Portfolio Allocation Balancing Account. In sum, significant policy and implementation issues are

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(stating "PG&E will be filing its 2022 PCIA Forecast on June 1. Given the request to reinstate the interim pool resources is pending approval by the Commission, the use of existing RPS resources to serve Solar Choice customer has not yet been reflected in the 2022 PCIA forecast that will be filed on June 1 as a carve out or as an offsetting credit. If the Commission approves PG&E's request in its Petition to Modify (PFM) to reinstate the use of the interim pool resources to support PG&E's Solar Choice Program, PG&E's November Update will reflect that a portion of the PCIA-eligible resource costs and volumes will be assigned to the GTSR program. This use of the interim pool resources can be accounted for either as a direct assignment of these resources to the GTSR program or can be accounted for in forecast and in recorded actuals by showing an offsetting GTSR credit to the PCIA-eligible contracts' vintage cost and volumes. In both cases, if the resources are dedicated to serve the GTSR Program exclusively, the market revenue for the resources would be credited to ERRA rather than PABA, along with a credit of the contract costs and volumes."). The Joint CCAs currently plan to address this suggested accounting treatment prior to the November Update.

21 A.21-06-001, PG&E Prepared Testimony at 9-8:10-16 to 9-9:1-4 and Table 9-2.

22 A.21-06-001, *Application of Pacific Gas and Electric Company (U 39 E) for 2022 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation*, pp. 20-22 (June 1, 2021).

frequently addressed in these proceedings, and the loss of a month of pre-update litigation will undermine parties' ability to address these issues and, in turn, diminish the adequacy of the record upon which the Commission relies to address them.

Further, while they rarely rise to the level of commanding a judge's attention, discovery disputes abound in these proceedings. The utilities frequently object to discovery requests, requiring intervenors to spend the time and resources necessary to navigate such disputes. For example, last year SCE initially refused to provide the RA and RPS-eligible volumes it forecasted would remain unsold in the forecast year, 2021. The parties met and conferred, and resolved the issue, but nearly 1.5 months passed between the SoCal CCAs' July 20, 2020 original data request and the final supplement to SCE's first responses, which were provided on September 1, 2020.[23] Similar disputes have plagued PG&E's proceedings.[24]

While the CCAs have hoped the Commission's recent decisions regarding data access and transparency would ease these tensions,[25] PG&E has thus far refused to provide confidential data to the Joint CCAs' reviewing representatives in its recently filed case, and a dispute currently exists in SDG&E's ERRA forecast case regarding both the utility's refusal to provide relevant data and SDG&E's treatment of certain data as confidential that neither of the other utilities labels confidential. These frustrating disputes demonstrate the difficulties intervenors continue to face in getting timely access to relevant data.

While it is clear the pre-update timelines of these cases should shift forward, such a shift must also accommodate the timing of load forecast data. SCE's Petition for Modification, filed

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[23] *See* A.20-07-004, *Joint Opening Brief of the Clean Power Alliance of Southern California and California Choice Energy Authority (The "SoCal CCAs") and the California Community Choice Association*, pp. 14-15 (Oct. 26, 2020).

[24] *See, e.g.,* A.19-06-001, *Motion to Compel of the Joint CCAs*, pp.1-10 (Nov. 11, 2019).

[25] D.20-12-035 at OP 8; D.20-12-038 at OP 4; D.21-01-017 at OP 6.

in R.01-10-024 ("SCE PFM"), resulted in that utility's current June 1 filing date.[26] The purpose of moving from May 1 to June 1 was to incorporate more accurate departing load forecasts, provided in April as a result of Resolution E-4907, which modified the process and timeline by which CCA load forecasts and RA obligations are determined.[27] Moving the update back a month squeezes the proceeding up against that mid-April load forecasting date.

The IOUs' filings undoubtedly are better with the most accurate CCA departing load information. However, the vast majority of load departures in major metropolitan areas have already taken place in California, or will take place in the next year. If load forecasts need to be modified, those modifications are likely to be less dramatic than those experienced over the past few years in the State, suggesting the "October Update" filing itself could accommodate changes brought on by newly departing load.

On balance, a May 1 filing date for SCE and PG&E would be the ideal date to accomplish Energy Division's goals while preserving the current pre-update timelines. If the CCA load forecasts cannot be incorporated by a May 1 filing date, and the Commission determines the update filing is an inappropriate vehicle to incorporate the CCAs' mid-April load forecasts, then a filing date in the first half of May for SCE and PG&E would also make sense.

All of these points go to support the following three conclusions:

1. If the Staff Proposal is adopted, PG&E and SCE should file one month earlier on May 1 or, at the very least, a filing date in the first half of May.

2. Because PG&E and SCE have already filed their 2022 forecast cases, the Staff Proposal should not be implemented until next year's ERRA forecast cycle.

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26 D.18-10-042 at 4 and Ordering Paragraph 2; *see also* R.01-10-024, *Petition for Modification of Southern California Edison Company (U 338-E) of Decision 14-05-006 to Establish New Filing Date For Its Annual ERRA Forecast Application* (Aug. 3, 2018).

27 D.18-10-042 at Finding of Fact 2.

3. To address the compressed November Update schedule for this year's ERRA forecast cases, CalCCA would respectfully request the Commission decision-makers, Energy Division Staff, and the Administrative Law Judges remain open to a Q1 2022 implementation schedule for this year's ERRA forecast proceedings. SCE itself has already recommended a Q1 implementation date.[28]

### C. Requiring the Same MDR Approach in All Three IOUs' Proceedings Will Increase the Efficiency of These Cases.

In D.20-12-035, the Commission found that "[c]ertain market participants, including CCAs, require timely access to SCE's ERRA/PABA/PUBA reporting as well as precise volume of RA, RPS and other metrics in order to meet their evidentiary burden in the ERRA forecast proceeding."[29] It further determined that delaying access to the "ERRA/PABA/PUBA and other reports concerning the validity of SCE's ERRA forecast application until the November Update, and requiring extensive discovery requests to obtain this information, creates additional administrative burdens for the parties to the proceeding as well as Commission staff."[30]

The Commission required SCE to "provide the following information in Energy Resource Recovery Account (ERRA) forecast proceeding workpapers and monthly ERRA compliance reports, starting January 2021:

(a) Confidential versions of monthly ERRA/PABA/PUBA activity reports;

(b) Additional detail supporting the monthly PABA reports, including subcategories for summarized line items such as utility-owed generation (UOG) costs and contracts

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[28] A.21-06-003, *SCE Prepared Testimony: Energy Resource and Recovery Account (ERRA) 2020 Forecast of Operations*, 4:3-8 (June 1, 2021) (stating "SCE respectfully informs the Commission that it currently takes SCE approximately four to five weeks to conduct the necessary testing and system updates in order to implement a rate change. Given the number and complexity of SCE's electric tariffs, SCE requires adequate time to update billing factors and run the necessary tests before it can implement new rates. SCE currently anticipates implementing a final 2022 ERRA Forecast decision in rates in the first quarter of 2022, though a January 1, 2022 rate change is likely infeasible given the five-week implementation requirement.")

[29] D.20-12-035 at Finding of Fact 38.

[30] *Id*. at 56.

(*e.g.*, provide by resource type, and whether Renewables Portfolio Standard (RPS) or non-RPS eligible);

(c) Actual or accrued volumetric quantities underlying each relevant dollar figure; such categories include UOG generation, power purchases and sales, California Independent System Operator market sales, and retail customer sales;

(d) Monthly accrued volumes of Actual Sold, Retained, and Unsold Resource Adequacy capacity; and

(e) Monthly accrued volumes of Actual Sold, Retained, and Unsold RPS-eligible energy.[31]

The Commission made nearly identical findings and orders in both PG&E and SDG&E's ERRA forecast decisions.[32]

However, in PG&E's case, the Commission required a Master Data Request ("MDR"),[33] specifying: "After PG&E has filed an ERRA forecast application, and so long as such application is pending, PG&E will provide the specified information to reviewing representatives that have signed a nondisclosure agreement within 5 days after it submits each monthly ERRA/PABA/PUBA activity report to the Commission."[34] Requiring this same process to be followed by all IOUs in their respective ERRA filings will ensure uniformity in CCAs' access to data and significantly improve efficiency in these expedited proceedings. Both SDG&E and SCE currently require the CCAs to submit discovery requests to obtain this information, eating into the already limited ability for parties to review this data. Requiring an MDR approach for those two utilities will further streamline the review of these cases.

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31 *Id*. at OP 8.

32 D.20-12-038 at 31-32 and OP 4; D.21-01-017 at OP 6.

33 D.20-12-038 at 31-32 and OP 4.

34 *Id*. at 31-32, Conclusion of Law 11, and OP 4.

## II. THE AMENDED SCOPING RULING AND D.21-05-030 PROVIDE SUFFICIENT NOTICE AND OPPORTUNITY TO BE HEARD.

During the Workshop, Commission staff raised questions about whether the filing dates for the ERRA forecast applications could be modified through a decision in this proceeding. While Staff's caution is appreciated, it would be difficult for an interested party to successfully argue they were not provided sufficient notice the issue would be addressed here. Such an uphill battle would be made even more difficult by the fact the result of this case would be to move a filing deadline for an application *forward* when the targeted decision date remains the same, *i.e.*, improving the procedural positioning of an intervenor.

Due process in California requires "notice reasonably calculated, under all the circumstances, to apprise interested parties of the pendency of the action and afford them an opportunity to present their objections."[35] The California Supreme Court has ruled on the application of this standard in the context of the Commission, finding, "[d]ue process as to the commission's initial action is provided by the requirement of 'adequate notice to a party affected and an opportunity to be heard before a valid order can be made.'"[36] Further, the California Supreme Court has recognized that, in determining the appropriate due process safeguards of a particular situation, "it must be remembered that 'due process is flexible and calls for such procedural protections as the particular situation demands.'"[37] The extent to which due process relief is available "depends on a careful and clearly articulated balancing of the interests at stake

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35 *Pacific Gas & Electric Co. v. Pub. Util. Comm'n*, 237 Cal. App. 4th 812, 859-60 (2015) (quoting *Mullane v. Cent. Hanover Bank & Trust Co.*, 339 U.S. 306, 314 (1950)).

36 *People v. Western Air Lines, Inc.*, 42 Cal. 2d 621, 632 (1954).

37 *People v. Ramirez*, 25 Cal. 3d 260, 268 (1979) (citing *Morrissey v. Brewer*, 408 U.S. 471, 481 (1972)).

in each context."[38] This analysis should consider the private interest affected by the official action and the "risk of an erroneous deprivation of such interest through the procedures used, and the probable value, if any, of additional or substitute procedural safeguards," as balanced against any countervailing governmental interest.[39]

The Commission has provided ample notice on multiple occasions to interested persons that the ERRA forecast process may change as part of this proceeding. Commissioner Guzman Aceves' December 16, 2020 Amended Scoping Ruling ("Amended Scoping Ruling") set forth two broad issues on the question:[40]

> 2) Should the Commission *modify deadlines or requirements of Energy Resource Recovery Account (ERRA) and PCIA related submittals and reports* in order to increase time for parties to review PCIA data and to facilitate timely implementation of decisions in the ERRA proceedings?
>
> 4) Should the Commission consider *any other changes* necessary to ensure efficient implementation of PCIA issues within ERRA proceedings?

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[38] *Id.* at 269.

[39] *Id.* The four relevant factors for determining whether a particular procedure comports with due process under the California Constitution, according to the California Supreme Court, are: "(1) the private interest that will be affected by the official action, (2) the risk of an erroneous deprivation of such interest through the procedures used, and the probable value, if any, of additional or substitute procedural safeguards, (3) the dignitary interest in informing individuals of the nature, grounds and consequences of the action and in enabling them to present their side of the story before a responsible governmental official, and (4) the governmental interest, including the function involved and the fiscal and administrative burdens that the additional or substitute procedural requirement would entail." *Id.* The analysis under the federal Constitution is similar, but does not include the analysis of the dignitary interest in factor three. *See Mohilef v. Janovici*, 51 Cal. App. 4th 267, 287 n.18 (1996); *Gilbert v. Homar*, 520 U.S. 924, 931-32 (1997).

[40] R.17-06-026, *Assigned Commissioner's Amended Scoping Memo and Ruling*, p. 1 (May 16, 2020) (emphasis added) ("Amended Scoping Ruling"). The Commission provided notice of the revised scope of this proceeding via service of the Amended Scoping Ruling. R.17-06-026, *Information Regarding Service*, p. 1 (Dec. 16, 2020) (service list notice accompanying the Amended Scoping Ruling).

The Amended Scoping Ruling also directed parties to answer three broadly-worded questions that mirror the two issues in the Scoping Ruling noted above.[41]

Moreover, the Commission stated in D.21-05-030 that broad reconsideration of the ERRA forecast proceedings' timelines would be addressed in this phase of this proceeding, stating: "We will continue to *explore ERRA proceeding timing*, ERRA data transparency, and methods for crediting or charging departing customers for ERRA balances."[42]

These statements make clear that the procedures related to ERRA forecast proceedings would be at issue in this phase of this case. The question of the date on which SCE and PG&E must file their ERRA forecast applications clearly falls within the scope of the term "ERRA and PCIA related submittals," "any other changes necessary to ensure efficient implementation of PCIA issues within ERRA proceedings," and "ERRA proceeding timing." Both the Amended Scoping Ruling and D.21-05-030 have apprised all interested parties of the pendency of these issues and afforded them an opportunity to present their objections.

Commission Staff suggested petitions for modification may be required to revise these filings dates, similar to the SCE PFM. However, Petitions for Modification are not required when an issue is within scope in an on-going proceeding to which interested parties could have intervened. Findings, conclusions and orders in subsequent proceedings can modify the findings, conclusions and orders in prior proceedings. The SCE PFM is distinguishable, for example, because it was filed at a time when there was no open docket considering the issue and, therefore, a PFM was necessary to provide notice to interested parties. Here, both the Amended Scoping Ruling and D.21-05-030 make clear the issue is in scope here. It would be an absurd

41 Amended Scoping Ruling at Attachment A.

42 D.21-05-030 at 6 (emphasis added).

result to require a PFM to change Commission findings from a prior proceeding regarding issues duly noticed as being in scope in a new proceeding. For example, the Commission did not require a PFM of D.11-12-018 in order to implement the revisions to the PCIA it adopted in D.18-10-019 earlier in this proceeding because doing so would be wildly inefficient and administratively burdensome.

Further, the balance of the interests at stake with regard to *moving up the start date* of a proceeding weigh in favor of the Commission moving forward expeditiously on a suite of procedural solutions. There is no property or pecuniary interest at stake because the question is merely one of process, and that change in process falls *in favor* of all non-utility interested persons. It is difficult to imagine a scenario where a party would be prejudiced by not having sufficient notice that a proceeding may start one month earlier than it began the prior year when, for example, the Commission does not have an intervention deadline, and the Applications are served on last year's participants. Moving up the start date, while keeping the final decision date the same, only increases interested parties' ability to litigate the proceeding, which would benefit all interested parties. In contrast, the SCE PFM reduced the time allowed for parties to litigate the proceeding, which certainly impacted parties' ability to represent their interests.

The probable value of additional or substitute procedural safeguards—here, requiring further notice or a PFM of prior decisions—would also be low. The parties to the last few years of ERRA forecast proceedings primarily have included the utility applicants, various CCA parties, direct access groups, The Utility Reform Network, agricultural parties, and CalAdvocates. All of these parties are parties to the instant proceeding. While there have been other parties to the ERRA forecast proceedings in the past few years, such as intervenors Sunrun, Inc., such parties would, as noted above, only benefit from having more time to litigate the proceeding.

The government's countervailing interests—here, to make sure that rates are accurate, that sufficient time exists to develop a robust record in support of those rates, and that all of the procedural short-comings Staff raised at the Workshop are addressed in a timely manner—include some of the foundational purposes for this Commission's existence. As a result, the "risk of an erroneous deprivation" is extremely low here where the countervailing governmental interest is high.

The Commission has provided adequate notice that the procedural components of the ERRA forecast—including the Application filing dates—may change as a result of this docket. There is no reason an order to move such dates up by a month cannot be included in a decision in this proceeding at this time. Delaying consideration of this issue will only delay its much-needed resolution to the procedural problems that have been discussed extensively on the record to date.

## III. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests the Commission adopt the Staff Proposal commensurate with the recommendations herein.

Respectfully submitted,

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*On behalf of*
California Community Choice Association

June 15, 2021

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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| Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes. | R.20-05-003 |

# REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION AND ALTERNATE PROPOSED DECISION REQUIRING PROCUREMENT TO ADDRESS MID-TERM RELIABILITY (2023-2026)

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June 15, 2021

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## I. INTRODUCTION

The California Community Choice Association[1] (CalCCA) submits these Reply Comments pursuant to Rule 14.3(d) of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on Administrative Law Judge Fitch's proposed *Decision Requiring Procurement To Address Mid-Term Reliability (2023-2026)* (PD), filed May 21, 2021; and Commissioner Rechtschaffen's *Alternate Proposed Decision Requiring Procurement To Address Mid-Term Reliability (2023-2026)* (APD), filed May 21, 2021.

## II. THE COST AND TIME NECESSARY TO CONDUCT A ROBUST LOSS OF LOAD EXPECTATION (LOLE) STUDY PRIOR TO ORDERING PROCUREMENT BEYOND THE MID-NEED SCENARIO IS WORTH ENSURING ANY RELIABILITY BENEFITS GIVEN THE POTENTIAL SIGNIFICANT COSTS

CalCCA continues to strongly support the adoption of the mid-need scenario procurement requirement of 7,500 MW, given the absence of analysis and modeling by the Commission to demonstrate that ordering the additional 4,000 MW required by the high-need scenario is necessary for reliability purposes. In opening comments, while some parties also opposed the adoption of the high need requirement,[2] even others such as PG&E who accepted the high-need requirement requested that the Commission establish a "workable process to systematically analyze and determine needs for CAISO system reliability" based on the "failure of the IRP process" demonstrated by this PD/APD.[3]

An important goal of the IRP process is to control costs for electric customers. Section 454.51(a) of the Public Utilities Code directs the Commission to "identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable

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[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] *See* AePR Opening Comments at 2-4; TURN Opening Comments at 2-4; Green Power Institute's Opening Comments at 1-4; Opening Comments of Middle River Power, LLC at 6.

[3] PG&E Opening Comments at 5-7 ("[t]he current PD/APD and the 2019 procurement track decision point to a failure of the IRP process to identify reliability planning needs and anticipate hurdles that need to be resolved for new resources to come online in a timely manner," and recommending an appropriate analysis, including an LOLE study for identifying CAISO system reliability procurement and for establishing a new planning reserve margin, and a stakeholder driven post-mortem analysis to assess the drivers of the current capacity shortfall).

energy in a cost-effective manner."[4] Section 454.52(a)(1)(D) further affirms that load-serving entities, in filing their IRP plans, should "minimize impacts on ratepayers' bills."[5]

Cost issues should be given more weight in this mid-term reliability analysis considering electric bill affordability issues the Commission has identified in other venues. According to the "Utility Costs and Affordability of the Grid of the Future" white paper initially presented at the Commission's February 24, 2021 En Banc on Energy Rates and Costs, electric rate projections through 2030 demonstrate that:

> for energy price sensitive households, bills are expected to outpace inflation over the coming decade. The implication is that… energy bills will become less affordable over time."[6]

The En Banc's white paper projections did not account for the PD/APD's 11,500 MW of proposed new build, and the affordability problem that might result.

In its opening comments, SCE presents its modeling regarding the actual costs of the Commission's addition of 4,000 MW by 2026.[7] SCE states that its "modeling shows a need for approximately 7,500 MW by 2026."[8] SCE further states that the additional 4,000 MW will actually not be required until 2030, and that "there has not been sufficient analysis justifying that all of this procurement must be accelerated to 2026."[9] In fact, SCE finds that ordering the procurement of "7,500 MW by 2025 and the remaining 4,000 MW in 2026 to 2030 ***saves customers approximately $2 billion in [net present value] system-wide by 2030.***"[10]

It is unclear whether the PD/APD complies with the Public Utilities Code and its clear mandate to control costs, or if it aligns with the Commission's other policy priorities as stated in the Rates En Banc White Paper. The PD cites no data or record showing any analysis of the cost impacts of the ordered procurement, and it is not known if the Commission considered whether the proposed

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4 Cal. Pub. Util. Code §454.51(a).

5 *Id.* at §454.52(a)(1)(D).

6 Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1 (Rates En Banc White Paper) at 5. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/EnergyElectricity_and_Natural_Gas/Senate%20Bill%20695%20Report%202021_En%20Banc%20White%20Paper.pdf

7 SCE Opening Comments at 5-6.

8 *Id.* at 5.

9 *Id.* at 6.

10 *Id.* (emphasis in original).

procurement targets are cost-effective, or if they would unduly impact ratepayers' bills with unneeded resources.[11] The only way to produce meaningful data on system costs is to perform system modeling.[12]

There is little downside risk in adopting the mid-need scenario (7,500 MW) now, with the commitment to conduct a full LOLE study in the next few months before committing to "final" procurement targets. In the worst case, the modeling affirms the need and mix of resources which can be developed to meet the 2026-2030 window. However, if the modeling shows a lower need or identifies a more cost-effective mix of resources, substantial cost savings to ratepayers could be realized.

## III. THE PROCUREMENT ALLOCATION TO EACH LSE SHOULD BE BASED ON PEAK LOAD SHARE, AS SET FORTH IN THE PD/APD

CalCCA supports the PD's/APD's adoption of a load share, hybrid peak load/energy allocation, rather than a contract allocation method, to allocate procurement requirements to all LSEs.[13] PG&E and TURN request modification of the PD/APD to require that the allocation be on a contract basis to account for LSE portfolio positions.[14] As set forth in CalCCA's Opening Comments on the ALJ Ruling, the contract position allocation method would have to be modified to be equitable to all LSEs.[15] The contract position method gives the IOUs 100 percent credit for PCIA portfolio resources, despite the allocation of cost responsibility for those resources to departing load customers. On balance, this will increase the proportion of new, accelerated resource costs that will be borne by CCA customers. Unlike IOU customers, however, there is no mechanism to provide compensation for these above-market costs. Unless PCIA resources are allocated *pro rata* among LSEs to determine their contract position, the Commission must utilize the hybrid peak load allocation approach as set forth in the PD/APD.

## IV. THE COMMISSION HAS PROVIDED NO EVIDENCE THAT PROCUREMENT OF INCREMENTAL FOSSIL-FUEL RESOURCES IS NECESSARY TO INCREASE RELIABILITY

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[11] Middle River Power LLC states that "[T]he Commission or parties [cannot] opine as to whether this procurement satisfies the Commission's obligations to ensure affordable rates, because no analysis regarding the potential costs of this procurement has been made." Middle River Opening Comments at 6.

[12] ALJ's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements, R.20-05-003, February 22, 2021; see CalCCA Opening Comments at 4-6; California Community Choice Association's Comments on ALJ's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements, March 26, 2021 (CalCCA Opening Comments on ALJ Ruling) at 2-6; California Community Choice Association's Reply Comments on ALJ's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements, April 9, 2021 at 2-4.

[13] PD at 52-53. On issues for which the PD and APD do not differ, CalCCA cites only to the PD.

[14] PG&E Opening Comments at 8; TURN Opening Comments at 9-11.

[15] CalCCA Opening Comments on ALJ Ruling at 5.

CalCCA agrees with SCE, TURN, CEERT, CEJA, the Sierra Club, Defenders of Wildlife, the Union of Concerned Scientists, and Vote Solar who contend that the Commission errs in requiring the IOUs to procure fossil-fueled capacity (in a range between 500MW-1,500 MW in the PD/APD), because the Commission has failed to demonstrate the need for such incremental gas generation or how this procurement will improve reliability or customer costs.[16] The Commission even admitted in the PD/APD that it chose to include the fossil fuel requirement as "insurance" amongst a "hierarchy of less-than-ideal choices" and cited the need to retain "public confidence" in the Commission's environmental goals for the electric sector.[17] However, the Commission has not identified the exact reliability attributes that will be met only by fossil fuel resources rather than by other resources or a combination of such resources. As a result, CalCCA urges the Commission to remove the fossil fuel requirement.

If, however, the Commission moves forward with its requirement for fossil fuel resources or a blend of fossil fuel and alternative fuels (such as green hydrogen), CalCCA supports the opening comments of Wärtsilä, North American, Inc. which requests that the Commission not restrict such alternative fuels to only green hydrogen, but also allow alternative carbon neutral fuels (such as bio-methane and ammonia) and/or technology configurations that can be used to achieve the same or greater GHG reduction at potentially lower costs.[18]

## V. THE COMMISSION SHOULD CLARIFY HOW RESOURCES ARE COUNTED TO ENSURE COMPLIANCE WITH THE PROCUREMENT ORDER

CalCCA requests that the Commission provide the following modifications and clarifications regarding LSE compliance obligations with procurement requirements that were raised in opening comments. First, as raised by AReM and the City of San Francisco/Peninsula Clean Energy, the Commission should provide a reduction of non-IOU LSE procurement obligations for any procurement by the IOUs with cost recovery from the LSEs through the CAM (such as fossil-fueled procurement by the IOUs).[19] Second, given the range of potential procurement obligations of the IOUs regarding fossil-

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16 SCE Opening Comments at 10; TURN Opening Comments, at 5; CEERT Opening Comments at 8; CEJA, Sierra Club, and Defenders of Wildlife Opening Comments at 4-8; Vote Solar Opening Comments at 7-11; Union of Concerned Scientists Opening Comments at 3-4.

17 PD at 38, 41.

18 Wärtsilä Opening Comments at 2-3. CalCCA was served with the Opening Comments of Wärtsilä, but acknowledges that the Commission has not yet granted Wärtsilä's Motion for Party Status or accepted the Opening Comments for filing.

19 AReM Opening Comments at 4-6; CCSF/PCE Opening Comments at 9.

fueled resources in the PD/APD, Table 7 should be clarified to show how such fossil-fuel requirements impact each LSE's overall minimum requirements.[20]

## VI. THE COMMISSION SHOULD REMOVE OR UPDATE THE 85% CAPACITY FACTOR FOR FIRM ZERO-EMITTING RENEWABLES

PG&E requests that the Commission remove or update the 85% capacity factor requirement with respect to the 1,000 MW of firm zero-emitting resources required in the PD/APD,[21] reasoning that the 85% capacity factor "does not make sense for the CAISO's system with sustained high solar generation throughout the day, especially during non-summer months."[22] PG&E reasons that such a high capacity factor resource will lead to mid-day negative prices and renewable curtailment, and that it is unclear if such a resource actually exists other than a nuclear resource.[23] CalCCA agrees that mandating procurement of a resource available with such high frequency given other resources in the portfolio is not supported by the record, and that further investigation is necessary into whether this high capacity factor will preclude most resources from qualifying as a firm zero-emitting resource.

## VII. CALCCA SUPPORTS THE REPLY COMMENTS FILED BY SAN DIEGO COMMUNITY POWER

San Diego Community Power (SDCP) has been in communication with CalCCA and is providing reply comments regarding the allocation of requirements with respect to new CCAs currently forming. CalCCA supports the comments filed by SDCP in this regard.

## VIII. CONCLUSION

CalCCA appreciates the opportunity to submit these Reply Comments and requests adoption of the recommendations proposed herein.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

June 15, 2021

20 SVCE/3CE Opening Comments at 12; CCSF/PCE Opening Comments at 8-9.
21 PD at 34.
22 PG&E Opening Comments at 14.
23 *Id.*

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

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|---|---|
| Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations. | R.19-11-009 |

# CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE PROPOSED DECISION

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June 15, 2021

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

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| Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations. | R.19-11-009 |

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S**
**REPLY COMMENTS ON THE PROPOSED DECISION**

The California Community Choice Association[1] (CalCCA) submits these Reply Comments pursuant to Rule 14.3(d) of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program* (Proposed Decision), filed May 21, 2021.

## I. INTRODUCTION AND RECOMMENDATIONS

CalCCA continues to support the positions taken in its opening comments and offers the following reply comments to supplement those positions. CalCCA recommends:

- A loss of load expectation (LOLE) study is the appropriate next step to inform an updated planning reserve margin (PRM)
- The Commission should not adopt the California Independent System Operator Corporation's (CAISO's) Resource Adequacy (RA) imports firm transmission proposal in this Proposed Decision
- The Commission should direct a Local Capacity Requirements (LCR) working group and consider recommendations resulting from that process
- Existing demand response contracts should count for resource adequacy even if they are not available on Saturday

## II. A LOSS OF LOAD EXPECTATION STUDY IS THE APPROPRIATE NEXT STEP TO INFORM AN UPDATED PLANNING RESERVE MARGIN (PRM)

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[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) state the Commission must provide direction in this Proposed Decision modifying the PRM for Resource Adequacy (RA) year 2023 and beyond and suggest the Commission adopt their proposal for a 17.5% PRM for 2023 and a 1-in-5 forecast plus 13% PRM for 2024 and onward.[2] CalCCA continues to oppose longer-term modifications to the PRM without more robust analysis vetted by the Commission, the CAISO, and stakeholders.

Cal Advocates suggests that using the future loss of LOLE study referenced in the Proposed Decision to inform PRM updates will create challenges for the RA program because "[a]ny deviation in the LSEs' actual procurement patterns could undermine the integrity of such an LOLE-driven PRM, requiring a new study with updated inputs and new capacity expansion assumptions."[3] The fact that the magnitude of the PRM needed to maintain the same level of reliability changes as the resource mix and other inputs change is true, regardless of how the PRM is established. However, without performing an LOLE study, California is left blind as to the level of reliability it is planning for, and how much of the existing fleet is needed as resource adequacy to meet that target. Increasing the PRM on a long-term basis without such robust analysis is misguided because it bypasses the critical exercise of determining the amount of capacity needed to meet a target level of reliability.

While Cal Advocates seems to suggest an LOLE study process to define the PRM is untenable due to its iterative or time intensive nature, it is common practice among ISO/RTOs in other areas to perform an LOLE study on a regular basis to set their planning reserve margins.[4] CalCCA recognizes that important policy discussions will need to be had about inputs, assumptions, and desired level of reliability. However, it is reasonable for the Commission and stakeholders to thoroughly vet a LOLE study in a timely manner to ensure planning targets reflect the desired level of reliability under the evolving grid. Because modifications to the PRM could significantly alter customer costs, the Commission has a responsibility to ground decisions in a robust analysis demonstrating that the increased PRM will maintain or improve reliability to a defined standard. Given this, CalCCA agrees

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[2] *Comments Of The Public Advocates Office On The Proposed Decision Adopting Local Capacity Obligations For 2022-2024, Flexible Capacity Obligations For 2022, And Refinements To The Resource Adequacy Program*, June 10, 2021, at 1.

[3] *Id.* at 4.

[4] MISO Resource Adequacy BPM Section 3.5 and PJM Manual 20: PJM Resource Adequacy Analysis Section 1.4 and 3.

with the Commission that an updated LOLE study is an appropriate next step to determine how the PRM should be revised.

## III. THE COMMISSION SHOULD NOT ADOPT THE CAISO'S RA IMPORTS FIRM TRANSMISSION PROPOSAL IN THIS DECISION

The CAISO proposed the Commission adopt its RA imports proposal or, at minimum, the firm transmission component of its proposal.[5] CalCCA previously supported the source specification, attestation, and must offer obligation aspects of the proposal but expressed concerns about the firm transmission requirement.[6] The Commission should not adopt the CAISO's proposed firm transmission requirement at this time and instead continue to evaluate the performance of existing rules while new import RA requirements are further discussed.

It is still unclear whether the proposal offers significant incremental reliability benefits compared to the increased cost to California load. Existing Commission rules codified in Decision (D.) 20-06-028 already require imports to bid such that they will very likely be scheduled during the availability assessment hours and they have existing incentives to ensure they can deliver energy when scheduled to avoid under delivery charges. The CAISO shared data indicating 21 different parties currently hold long-term firm transmission rights on the California Oregon Border and the Nevada Oregon Border intertie.[7] However, without understanding the concentration of each party's share of firm transmission, the concern remains over the ability to obtain firm transmission to meet the proposed requirement. While numerous parities may have firm transmission rights on a particular path, one or a few parties may hold a significantly high share of those rights. Additionally, a portion of intertie transmission rights will be held by entities looking to use it to serve their own load outside of California. Simply pointing to the number of parties holding firm transmission rights is not sufficient to conclude the market for firm transmission is liquid enough to avoid adverse consequences of the proposed requirement. Mandating firm transmission as a prerequisite to providing RA, however, will limit the pool of available import RA resources to only those who can

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5 *Opening Comments On Proposed Decision Adopting Local Capacity And Flexible Capacity Obligations Of The California Independent System Operator Corporation*, June 10, 2021 *(CAISO Opening Comments)*, at 1-2.

6 *Opening Comments Of The California Community Choice Association On Track 3B.1 And Track 4 Revised Proposals*, Mar. 12, 2021,
at 13.

7 CAISO Opening Comments at 5.

secure firm transmission, even when import RA can reliably deliver without it, and increase costs to ratepayers.

Given the potential increased costs without clear reliability benefit, CalCCA supports the Commission's Proposed Decision to continue to evaluate current rules before adopting a firm transmission requirement. The CAISO's RA imports proposal is currently under consideration in the RA Enhancements initiative, and the CAISO has recently announced a new initiative External Load Forward Scheduling Rights Process that will commence this July to develop a prioritization process for wheel-through transactions. CalCCA sees benefit in continuing to consider this proposal in conjunction with the new initiative given potential areas for coordination.

## IV. THE COMMISSION SHOULD DIRECT A LCR WORKING GROUP AND CONSIDER RECOMMENDATIONS RESULTING FROM THAT PROCESS

Calpine and Middle River Power do not oppose a LCR working group but suggest any recommended changes resulting from the working group process should not be adopted in a Commission forum but rather through the CAISO's existing process or at the Federal Energy Regulatory Commission.[8] CalCCA disagrees and finds significant benefit in exploring the issues outlined in the Proposed Decision[9], as well as alternative solutions to the local area needs for the Pacific Gas and Electric Company's Greater Bay Area as outlined in CalCCA's comments to the Proposed Decision.[10] Public Utilities Code Section 380 (a) and (b) states, "The commission, in consultation with the Independent System Operator, shall establish resource adequacy requirements for all load-serving entities," and "[i]n establishing resource adequacy requirements, the commission shall ensure the reliability of electrical service in California…," clearly outlining a collaborative process in which the Commission and the CAISO work together to establish resource adequacy requirements that ensure reliable service. As such, the Commission is free to convene a working group to examine the process by which local area requirements are established, consider suggestions resulting from the working group, and make decisions about how best to achieve local area reliability.

## V. EXISTING DEMAND RESPONSE CONTRACTS SHOULD COUNT FOR RA EVEN IF THEY ARE NOT AVAILABLE ON SATURDAY

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8 *Comments Of Calpine Corporation On Proposed Decision Adopting Local Capacity Obligations For 2022-2024, Flexible Capacity Obligations For 2022, And Refinements To The Resource Adequacy Program,* June 10, 2021, at 2; and *Middle River Power LLC Opening Comments On Proposed Decision Adopting Local Capacity Obligations For 2022- 2024, Flexible Capacity Obligations For 2022, And Refinements To The Resource Adequacy Program*, June 10, 2021, at 3-4.

9 Proposed Decision at 13.

10 *California Community Choice Association's Comments on the Proposed Decision*, June 10, 2021, at 14.

Southern California Edison Company (SCE) expressed concerns about the impact of requiring Saturday availability on existing demand response (DR) contracts and suggested DR resources under existing contracts executed before the effective date of the Decision be exempt from the Saturday availability requirement. [11] This is a reasonable approach. DR contracts already executed prior to the effective date of this decision should continue to count toward RA and towards the DR Maximum Cumulative Capacity (MCC) bucket if they are not available on Saturdays. This would allow existing DR resources already under contract to continue to provide RA value, giving time to update DR programs and sign new contracts with DR resources designed to be available on Saturdays.

## VI. CALCCA AGREES WITH SCE'S OPENING COMMENTS ON HOW THE PROVIDER OF LAST RESORT (POLR) WOULD BE TREATED UNDER THE REVISED PENALTY STRUCTURE, SUBJECT TO CLARIFICATION

In comments to the proposed penalty structure revisions, SCE requests the Commission clarify that the POLR will not accrue points for any deficiency where the POLR qualifies for the system RA waiver adopted in D.20-06-031.[12] CalCCA generally agrees with the following clarification: the POLR should not accrue any points for any deficiencies resulting from unexpected load returns for which the Commission grants a system waiver. This clarification makes it clear that only the portion of a deficiency attributable to unexpected returning load would receive a point-accrual exemption and only if the Commission grants the waiver requested by the POLR.

## VII. CONCLUSION

CalCCA appreciates the opportunity to submit these Reply Comments and requests adoption of the recommendations proposed herein.

Respectfully submitted,

Evelyn Kahl
General Counsel to the
California Community Choice Association

June 15, 2021

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[11] *Southern California Edison Company's (U 338-E) Opening Comments On Proposed Decision Adopting Local Capacity Obligations For 2022-2024, Flexible Capacity Obligations For 2022, And Refinements To The Resource Adequacy Program*, June 10, 2021, at 3-4.

[12] *Id.* at 7.

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

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|---|---|
| Order Instituting Rulemaking to Address Energy Utility Customer Bill Debt Accumulated During the COVID-19 Pandemic. | R.21-02-014<br>(February 11, 2021) |

# REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION

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June 21, 2021

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SUMMARY OF RECOMMENDATIONS

- The Commission should act immediately to extend the suspension (currently set to expire on June 30, 2021) of the "utility first" partial payment waterfall to allow the pro rata allocation of customer partial payments among the IOUs and CCAs to continue through the term of the COVID-19 relief payment plans established in the Proposed Decision.

- The Commission should adopt automatic enrollment in the COVID-19 Relief Payment Plan, but not the Arrearage Management Plan.

- The proposals of SDG&E and PG&E to suspend disconnections for CARE and FERA customers while utility debt relief is being finalized should be adopted.

- The Proposed Decision should include any developments concerning federal and state COVID-19 related debt relief, as well as delineate issues to be resolved in Phase 2 including CCA arrearage relief and recovery of IOU costs concerning debt relief programs.

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

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| Order Instituting Rulemaking to Address Energy Utility Customer Bill Debt Accumulated During the COVID-19 Pandemic. | R.21-02-014 (February 11, 2021) |

**REPLY COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED DECISION**

The California Community Choice Association[1] (CalCCA) submits these Reply Comments pursuant to Rule 14.3(d) of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment In Long Term Payment Plans* (Proposed Decision), issued on May 24, 2021.

## I. INTRODUCTION

CalCCA appreciates the opportunity to provide these Reply Comments. CalCCA's opening comments focused primarily on a critical issue for community choice aggregators (CCAs), identified as Issue 7.c. in the Proposed Decision, regarding the allocation methodology for partial payments made by customers under the adopted payment plan.[2] Requirements in the tariffs of Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) regarding allocation of partial payments to investor-owned utility (IOU) arrearages prior to the application of payments to CCA arrearages were suspended by Commission Resolutions M-4842 and M-4849 during the COVID-19 pandemic, through June 30, 2021. The effect of the suspension is to allow the pro rata allocation to IOUs and CCAs of any partial

1 California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 Proposed Decision at 14, Issue 7.c.

payments. Given the impending expiration of pro rata payment allocation, the Commission should act immediately to extend to allow the pro rata allocation of partial payments to continue through the term of the COVID-19 relief payment plans established in the Proposed Decision.

The reply comments below address additional issues raised in opening comments that CalCCA did not previously discuss. CalCCA does not change its position on any of the topics that it did raise in opening comments, but rather uses this opportunity to expand or address on the following additional issues:

- The Commission should adopt automatic enrollment in the COVID-19 Relief Payment Plan, but not the Arrearage Management Plan (AMP);
- The proposals of SDG&E and PG&E to suspend disconnections for California Alternate Rates for Energy (CARE) and Family Electric Rates Assistance (FERA) customers while utility debt relief is being finalized should be adopted; and
- The Proposed Decision should include any developments concerning federal and state COVID-19 related debt relief, as well as delineate issues to be resolved in Phase 2 including CCA arrearage relief and recovery of IOU costs concerning debt relief programs.

## II. CALCCA SUPPORTS AUTOMATIC ENROLLMENT IN THE COVID-19 RELIEF PAYMENT PLAN, BUT NOT IN AMP

As set forth in its opening comments, CalCCA supports the Proposed Decision's plan for automatic enrollment of customers in the COVID-19 Relief Payment Plan.[3] CalCCA does not, however, support automatic enrollment in the AMP, as requested in the opening comments of The California Environmental Justice Alliance (CEJA), Leadership Counsel for Justice and Accountability (LCJA) and The Greenlining Institute (Greenlining).[4] Customers are currently enrolled in the AMP program on a request to participate basis (and not auto-enrolled).

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3 *Comments of California Community Choice Association on the Proposed Decision* (CalCCA Opening Comments), June 14, 2021, at 8-9.

4 *Opening Comments of CEJA, LCJA and Greenlining on Proposed Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment in Long Term Payment Plans,* June 14, 2021 (CEJA, LCJA, and Greenlining Opening Comments), at 5-6 (requesting auto-enrollment of customers with arrears into AMP, as an alternative to extending disconnection moratorium and designing a "comprehensive program" in phase 2 of this proceeding "with automatic enrollment in enhanced payment plans with debt forgiveness . . . ."). CEJA, LCJA and Greenlining erroneously state that the AMP program "include[s] forgiveness of half of a customer's arrears if they make all of the qualifying payments." CEJA, LCJA and Greenlining Opening Comments at 6. The AMP rules set forth in the Disconnection Proceeding phase 1 decision instead set forth that "the AMP structure consists of a 12-month payment plan that forgives 1/12 of a customer's arrearage after each on-time payment of the existing month's bill is adopted." D.20-06-003, *Phase 1 Decision Adopting Rules and Policy Changes to*

While the Commission should adopt automatic enrollment for COVID relief plans, there are problems with applying automatic enrollment to the AMP. First, based on the rules outlined in the Disconnection Proceeding (Rulemaking (R.) 18-07-005) Phase 1 Decision, Decision (D.) 20-06-003, if customers are auto enrolled in AMP, those who do not know the AMP program rules may miss payments. This would inadvertently block the customer from AMP benefits for an entire year.[5] Second, because the COVID-19 relief plans and AMP differ in terms and conditions, automatic enrollment in both would create a conflict. Automatic enrollment in the COVID-19 relief plans should be primary, with customers electing alternatively to participate in AMP. Third, the AMP is funded through the Public Purpose Program Charge (PPPC) by ratepayers, while the COVID-19 relief plans will be funded first by state and federal relief funds. Relief funds should be expended first, before resorting to recovery of arrearages under AMP from ratepayers through the PPPC.

Rather than changing the AMP rules to allow auto-enrollment, the Commission should adopt the COVID-19 Relief Payment Plan as set forth in the Proposed Decision, to assist struggling ratepayers while the details concerning federal and state relief for arrearages are worked out.

## III. THE PROPOSALS OF SDG&E AND PG&E TO SUSPEND DISCONNECTIONS FOR CARE AND FERA CUSTOMERS WHILE UTILITY DEBT RELIEF IS BEING FINALIZED SHOULD BE ADOPTED

CalCCA supports the proposals of SDG&E and PG&E to extend the suspension of disconnections for CARE and FERA customers beyond June 30, 2021. This will ensure that residential customers on the verge of receiving utility debt relief are not inadvertently disconnected.[6]

In any such extension, the Commission must also extend the suspension of PG&E's and SDG&E's "utility first" partial payment waterfall. As discussed in CalCCA's opening comments,[7] ensuring that all partial past due payments from customers are applied to IOU and

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*Reduce Residential Customer Disconnections For the Larger California-Jurisdictional Energy Utilities* (Disconnection Decision), June 16, 2020, at 103.

5 Disconnection Decision at 103.

6 *Opening Comments of SDG&E (U 902 M) on the Proposed Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment in Long Term Payment Plans*, June 14, 2021, at 6-7; *PG&E (U39M) Opening Comments on the Proposed Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment in Long Term Payment Plans*, June 14, 2021, at 11-12.

7 CalCCA Opening Comments at 2-8.

CCA balances in proportion to their arrearages assures that neither load-serving entity is placed at a financial disadvantage.

## IV. THE PROPOSED DECISION SHOULD INCLUDE DEVELOPMENTS CONCERNING FEDERAL AND STATE COVID-19 RELATED DEBT RELIEF AND DELINEATE PHASE 2 ISSUES REGARDING CCA ARREARAGE RELIEF AND RECOVERY OF IOU COSTS

CalCCA agrees with the Center for Accessible Technology (CforAT) and National Consumer Law Center (NCLC) that the Proposed Decision should be updated to reflect the most recent developments regarding the utility debt relief programs, both federal and state, that have already been already implemented and those that are on the horizon.[8]

In addition, the Proposed Decision defers determinations other than the establishment of long-term payment plans to a second phase of this proceeding in light of potential federal and state relief.[9] The second phase should include any unresolved issues concerning relief for CCA pandemic-related arrearages, which was addressed in more detail in CalCCA's opening comments.[10] CalCCA also agrees with the Public Advocates Office at the California Public Utilities Commission's request that the Proposed Decision should delineate how the second phase will address the recovery through rates of the IOU costs regarding the implementation of the payment plans, securing utility arrearage relief funds from state and federal sources, and outreach costs.[11]

In addressing all arrearages arising from the COVID-19 pandemic, the Commission's adopted rules must equitably address IOU and CCA financial positions. This will require ensuring that: (1) past due partial payments and payment plan payments are applied pro rata to IOU and CCA balances; (2) all state and federal relief funds are applied pro rata to IOU and

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8 *See CforAT and NCLC Opening Comments on Proposed Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment in Long Term Payment Plans,* June 14, 2021, at 8-10.

9 Proposed Decision at 3, 14.

10 CalCCA's Opening Comments detail the pandemic-related arrearages which highlight the substantial financial challenges faced by both IOUs and CCAs. For example, of PG&E's reported total residential customer arrearages of $654 million, CCA customers account for $255 million (40%) of those arrearages. CalCCA Opening Comments at 7 (citing *Response of Pacific Gas and Electric Company (U 39 M) to the Administrative Law Judge's Ruling Directing Utilities to Provide Data,* Mar. 30, 2021, Attachment A, Table 6, at 11, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M376/K042/376042388.PDF).

11 *Opening Comments of the Public Advocates Office on the Proposed Decision Addressing Energy Utility Customer Bill Debt Via Automatic Enrollment in Long Term Payment Plans,* June 14, 2021, at 2.

CCA balances; and (3) any balance not covered by state and federal relief funds are recovered through the PPPC, consistent with the methodology adopted for the AMP.[12]

## V. CONCLUSION

CalCCA appreciates the opportunity to submit these Reply Comments and requests adoption of the recommendations proposed herein.

Respectfully submitted,

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Evelyn Kahl
General Counsel to the
California Community Choice Association

June 21, 2021

[12] *California Community Choice Association Comments on Order Instituting Rulemaking,* Mar. 3, 2021, at 6-7; *California Community Choice Association Opening Brief,* Apr. 23, 2021, ("CalCCA recommends recovering the cost of debt forgiveness through the PPPC"); at 3-4; and *California Community Choice Association Reply Brief,* Apr. 30, 2021; Resolution E-5114, Dec. 17, 2020 (adopting AMP).

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

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|---|---|
| Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment. | Rulemaking 17-06-026 (Filed June 29, 2017) |

# CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS IN RESPONSE TO STAFF'S ERRA TIMING PROPOSAL


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*On behalf of*
California Community Choice Association


June 22, 2021

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

| | |
|---|---|
| Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment. | Rulemaking 17-06-026<br>(Filed June 29, 2017) |

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS IN RESPONSE TO STAFF'S ERRA TIMING PROPOSAL**

Pursuant to Administrative Law Judge Wang's May 20, 2021 E-mail Ruling,[1] the California Community Choice Association[2] ("CalCCA") submits the following reply comments on Energy Division Staff's proposal to revise the publication date for the Power Cost Indifference Adjustment ("PCIA") Market Price Benchmarks ("MPBs") from November 1 to October 1 of each year ("Staff Proposal").[3]

A number of areas of agreement arose in parties' opening comments:

- Parties agree the prudent course would be to wait to implement the Staff Proposal until the 2023 ERRA forecast cycle.[4]

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

2 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy Authority, 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, Silicon Valley Clean Energy Authority, Solana Energy Alliance, Sonoma Clean Power Authority, and Valley Clean Energy.

3 R.17-06-026, Energy Division Staff, *Revision of the Power Cost Indifference Adjustment Market Price Benchmarks calculation date from November 1 to October 1 of each year* (May 20, 2021) ("Staff Proposal").

4 R.17-06-026, *Comments of San Diego Gas & Electric Company (U 902 E) on Market Price Benchmark Staff Proposal*, pp. 2-3 (June 15, 2021) ("SDG&E Opening Comments"); R.17-06-026, *Joint*

- No party opposed Staff conducting more analysis to ensure moving the MPB publication date forward by a month would not have an oversized impact on the accuracy of the benchmarks.[5]
- ERRA forecast cases in the near-future will include substantive policy and implementation issues that the Commission will need to address,[6] which supports the position advanced in CalCCA's opening comments that timelines prior to the update must be maintained.[7]

While such agreement is encouraging, other proposals that would reduce timelines for intervenors, broaden the scope of issues to be resolved in the forecast proceedings, or limit parties' opportunity to agree on departing load forecasts will work against the goals laid out in the Staff Proposal. CalCCA urges the Commission to adopt Staff's Proposal, while moving forward PG&E and SCE's ERRA forecast filing dates, as part of the instant proceeding for implementation in the 2023 ERRA forecast cycle.

## I. THE FIRST STEP SHOULD BE TO DO NO HARM.

The creative ideas put forward by the Joint IOUs with regard to ways to modify the typical ERRA proceedings are welcome. However, as stated numerous times over the course of

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*Comments of Southern California Edison Company (U 338-E) and Pacific Gas and Electric Company (U 39 E) on the Energy Division Staff Proposal Concerning the Timing of the Market Price Benchmarks*, p. 4 (June 15, 2021) ("Joint IOU Comments").

5 SDG&E Opening Comments at 2; Joint IOU Comments at 4, 6. While the Joint IOUs state "SCE incurred significant costs conducting RA solicitation to meet the year-ahead requirements," and "PG&E is similarly concerned that any such RA costs would then not be included in an October Update," it is difficult to believe the costs of *running* an RA solicitation would have much impact on the MPBs. Joint IOU Comments at 6. If the IOUs' statements mean the Joint IOUs had to conduct a substantial amount of last-minute RA procurement to meet changing RA requirements, the CCAs have had similar experiences. However, generally, adjustments to the Commission's final RA requirements could "go either way" in terms of MPB impacts.

6 Joint IOU Comments at 5 (discussing issues related to the Central Procurement Entity and Voluntary Allocation Mechanism).

7 R.17-06-026, *California Community Choice Association's Comments in Response to Staff's ERRA Timing Proposal*, pp. 4-12 (June 15, 2021) ("CalCCA Opening Comments").

this proceeding, and the ERRA proceedings, the fundamental problem with the current process is the insufficient amount of time available to complete the work that needs to be completed.[8] The scope of work to be accomplished has only increased as different proceedings and utility proposals require more issues to be addressed in these cases. Changes that would result in *less* time for intervenors to analyze the application, or could lead to more issues being scoped into these proceedings, are almost certain to be more harmful than helpful.

The Joint IOUs' request to modify standard procedural timelines for protests and replies appears aimed at reducing the time allowed for those procedural mechanisms.[9] This approach would appear to only exacerbate the current problems with the condensed schedule, especially with the frequent discovery and scoping issues the CCAs have identified.[10]

Similarly, establishing a "set" procedural scope supporting January 1 rate implementation,[11] with additional issues as part of a second procedural track in each case, could open the floodgates to even more policy issues being considered in these recurring cases. Prolonged litigation that increases costs for intervenors, and the potential for multiple, off-cycle, rate changes that increase rate uncertainty, weigh heavily against such an approach. The Commission already has the ability to create parallel tracks in ERRA proceedings, as appropriate, and has done so, including the original PCIA working group that led to the

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8 Statements from the Joint IOUs that these cases, and particularly the November Update, are formulaic and mechanical ignore reality. Joint IOU Comments at pp. 1-2, n. 2. The CCAs, both in the ERRA forecast proceedings and throughout this proceeding, have refuted this position time and again, and the IOUs' repeatedly short memories on the intense efforts and disputes that recur in November each year, in particular in PG&E's and SDG&E's recent cases must be given little weight.

9 Joint IOU Comments at 4.

10 *See, e.g.*, CalCCA Opening Comments at 7, 10.

11 Joint IOU Comments at 4.

Commission instituting the instant proceeding,[12] or the Phase 2 in PG&E's 2017 ERRA forecast proceeding to address cost responsibility for pre-2009 direct access customers.[13] Thus, it is not clear this proposal would provide an improvement to the *status quo*.

The most basic principle of any timing changes related to the ERRA proceedings should be "do no harm" to parties' already limited ability to litigate these cases and the Commission's ability to resolve them. While the suggestions in the Joint IOUs' comments are appreciated, reducing timelines, or introducing mechanisms that could lead to a broader scope, would conflict with that principle. The Staff Proposal is a sensible first step to addressing the issues at hand, provided the current timelines prior to the October Update are maintained and staff's analysis verifies that moving to an October Update would have minimal impact on the accuracy of the MPBs.

## II. IT IS IMPORTANT TO MAINTAIN TWO MEET AND CONFERS IN PG&E'S SERVICE TERRITORY.

The Joint IOUs' request to move the second meet-and-confer in PG&E's service territory ahead one month aligns with the portion of CalCCA's Opening Comments requesting the Commission maintain all typical pre-update timelines;[14] but the request to eliminate it altogether should not be adopted. PG&E observes that "[a]n early-October Update to Prepared Testimony is incompatible with PG&E's regulatory obligations applicable to its update to load forecasts."[15] In PG&E's view, this incompatibility is due to the fact the update "includes a load

[12] A.14-05-024, *Southern California Edison Company's (U 338-E) Submission of the Final Report of the PCIA Working Group*, p. 1 (April 5, 2017) (implementing D.16-09-044 on behalf of SCE and Sonoma Clean Power Authority).

[13] D.19-12-010 at 1.

[14] Joint IOU Opening Comments at 4-6; CalCCA Opening Comments at 4-12.

[15] Joint IOU Opening Comments at 5.

forecast informed by a meet-and-confer process with CCA[s].”[16] PG&E's concern is that the meet and confer process leaves insufficient time to revise the load forecast for the October Update to Prepared Testimony.

The Joint IOUs propose two alternatives to address this concern. Alternative one is to move “the meet-and-confer process forward to August 15 at the latest.”[17] Alternative two is to eliminate the meet-and-confer process that informs the October Update.[18] CalCCA pointed out the timing issue that an October Update would present in our opening comments, and the current meet-and-confer process is an additional step that needs to move forward by one month. Accordingly, adoption of Staff’s proposal should be accompanied by a shift in the second meet-and-confer in lockstep with the shift from a November to an October Update (*i.e.*, to conclude by August 15th).

Altogether eliminating the second meet and confer will make an already difficult process more dysfunctional. Issues addressed in the meet-and-confer extend beyond just those associated with “CCA formation and expansion,” and the underlying rationale to “improve the accuracy of forecasts” for the Commission requiring a second meet-and-confer remains valid today.[19] The meet-and-confer process has featured numerous disagreements between CCAs and PG&E, as elaborated on below. The second meet and confer process is important because it results in the forecast used in the final rates, and provides an opportunity to resolve issues not fully addressed in the first meet-and-confer process.

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16 *Id.*

17 *Id.*

18 *Id.*

19 D.16-12-038 at 14.

The meet-and-confer process is about more than just forecasting departing load. Disputes between IOUs and PG&E have involved, variously, forecasts of monthly energy; peak contribution; and data issues such as customer count by customer class; hour of the peak in PG&E data and information on whether that is the customer level non-coincident peak, PG&E's coincident system peak, individual CCA coincident system peak, or CAISO coincident system peak. Pertinent to the need for a second round of meet-and-confer, not all issues are addressed by the end of the February process. For instance, last year PG&E did not supply "customer-specific information consisting of: service agreement number, monthly interval meter data where available, and rate schedule for all accounts within the CCA's territory"[20] in time for incorporation into CCA February forecasts. Given these challenges, it remains important for PG&E and the CCAs to have as many opportunities as possible to work out their differences, and to ensure all impacted customers have a say in the final forecast numbers.

## III. THE COMMISSION SHOULD ACT WITHIN THIS PROCEEDING OR PROVIDE CLEAR GUIDANCE ON WHERE ACTION CAN TAKE PLACE.

Lastly, as explained in detail in CalCCA's Opening Comments, the Commission has the ability to address all of these procedural issues in the instant proceeding due to the broad scope afforded by the Assigned Commissioner's Scoping Ruling and D. 21-05-030.[21]

The Joint IOUs propose that the parties file and serve a "report" for party comment in each IOU's respective ERRA forecast docket recommending going-forward procedural changes, if any, by October 1, 2021.[22] While the term "report" is a little unclear, it seems the suggestion

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20 This is known as "item17" data, referencing PG&E ELECTRIC SCHEDULE E-CCAINFO - INFORMATION RELEASE TO COMMUNITY CHOICE AGGREGATORS, paragraph 17 (available at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-CCAINFO.pdf).

21 CalCCA Opening Comments at 14-18.

22 Joint IOU Opening Comments at 2.

would be for parties to include comments on a set of procedural changes to potentially be adopted in each ERRA forecast case, with these changes applied in future ERRA forecast cases. This approach would be acceptable if the Commission disagrees with CalCCA that much-needed solutions can be adopted here and now. Alternatively, if the Commission continues to believe petitions for modification are necessary to enact various solutions, including moving the IOUs' filing dates forward, parties would greatly benefit from clear direction along these lines in the Commission's decision on this phase of this proceeding.

However, the potential for more process that is duplicative of the instant process, and the potential for disjointed and conflicting solutions across the three IOUs, caution against these alternative approaches. The simplest and most direct outcome is to utilize this proceeding to implement Staff's proposal with the required adjustments described herein.

## IV. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests the Commission adopt the following within this proceeding:

- Implement the Staff Proposal next year (*i.e.*, during the IOUs' 2023 ERRA forecast cases);
- Maintain the current, typical procedural schedules for the ERRA forecast proceedings that occur prior to each year's update, including the meet-and-confer schedule;
- Require SCE and PG&E to file their ERRA forecast applications on May 1 each year instead of June 1, or, at the very least, on a filing date in the first half of May;
- Target Q1 2022 implementation for this year's ERRA forecast proceedings, similar to SCE's request in its 2022 ERRA forecast application; and
- Adopt the Master Data Request approach for the SCE and SDG&E ERRA forecast proceedings that is currently utilized for the PG&E proceeding.

CalCCA appreciates the Commission's attention to these issues.

Respectfully submitted,

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*On behalf of*
California Community Choice Association

June 22, 2021

**Stakeholder Comments Template**

**RAAIM Exemption Options for Demand Response Resources**

This template has been created for submission of stakeholder comments on the final proposal and draft tariff language that was published on June 10, 2021 The proposal, Stakeholder meeting presentation, and other information related to this initiative may be found on the initiative webpage at: http://www.caiso.com/informed/Pages/MeetingsEvents/MiscellaneousStakeholderMeetings/Default.aspx.

Upon completion of this template, please submit it to initiativecomments@caiso.com. Submissions are requested by close of business on **June 23, 2021**.

| Submitted by | Organization | Date Submitted |
|---|---|---|
| *Lauren Carr lauren@cal-cca.org* | *California Community Choice Association (CalCCA)* | *6/23/21* |

**Please provide your organization's comments on the following issues and questions.**

CalCCA supports a Resource Adequacy Availability Incentive Mechanism (RAAIM) exemption for demand response resources with variable load reduction capability. Rather than limit the RAAIM exemption to resources with an Effective Load Carrying Capability (ELCC), however, the CAISO should provide the RAAIM exemption to demand response resources with variable capability valued in a manner that the CAISO and the local regulatory authority determine effectively measures their capability.

1. **Variable-Output Demand Response (DR)**

   Please provide your organization's feedback on the proposal to treat demand response as a variable-output resource, as previously vetted through the Energy Storage and Distributed Energy Resources (ESDER) Phase 4 initiative, and consistent with anticipated changes by the California Public Utilities Commission (Commission). Please explain your rationale and include examples if applicable.

   The CAISO correctly states that because the load of underlying customers within a demand response resource changes with time of day, weather, and other factors, the load reduction capability of the resource changes day to day or hour to hour. Similarly situated resources such as wind, solar, and hydro also have variable capabilities and are also offered a RAAIM exemption. As such, it is prudent to exempt demand response resources with this variability from RAAIM.

**2. RAAIM Exemption Option for Variable-Output DR**

Please provide your organization's feedback on the propose to exempt variable-output DR from the Resource Adequacy Availability Incentive Mechanism (RAAIM). Please explain your rationale and include examples if applicable.

The CAISO's Final Proposal states the CAISO will exempt Proxy Demand Resource (PDR) or Reliability Demand Response Resources (RDRR) from RAAIM if they are valued under an ELCC methodology or similar methodology that meets the following principles:

- Assesses Demand Response's (DR's) contribution to reliability across the year or seasons as a variable-output resource, and;
- Assesses DR's interactive effects with other similarly-situated resources.[1]

Determination of whether a variable demand response resource receives a RAAIM exemption should not lie solely on the local regulatory authority's adoption of an ELCC. In its Track 3B1 and 4 Proposed Decision, the California Public Utilities Commission (Commission) recognized demand response as a variable resource but did not adopt the CAISO's principles or an ELCC counting methodology. Instead, the Commission requests the California Energy Commission (CEC) begin a stakeholder process to explore and make a recommendation on demand response capacity counting including, "(1) Whether CAISO's ELCC proposal is reasonable and appropriate to determine DR QC and/or what modifications, if any, should be considered; (2) Whether the LIP + ELCC proposal is reasonable and appropriate to determine DR QC and/or what modifications, if any, should be considered; [and] (3) Whether other proposals that may be presented in the CEC's stakeholder process are reasonable and appropriate to determine DR QC..."[2] This leaves considerable room in the stakeholder process for parties to introduce new or modified principles for demand response counting and make alternative proposals for determining DR's QC value beyond an ELCC.

Given this, it is premature for the CAISO to tie the RAAIM exemption to an ELCC or declare the CAISO as the sole entity that determines whether an alternative methodology meets the criteria for a RAAIM exemption. There are many ways to measure the resource adequacy value of resources with variable output. While wind and solar resources are currently valued under an ELCC by the Commission, run-of-river hydro resources are valued under an exceedance methodology. Rather than limit the RAAIM exemption to resources with an ELCC, the CAISO should provide the RAAIM exemption to demand

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[1] *Resource Adequacy Availability Assessment Mechanism (RAAIM) Exemption Option For Variable-Output Demand Response Valued Under an Effective Load Carrying Capability (ELCC) or Similar Methodology*, June 10, 2021 (Final Proposal), at 2.

[2] *Proposed Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program*, May 21, 2021, at 35.

response resources with variable capability valued in a manner that the CAISO and the local regulatory authority determine effectively measures their capability.

**Additional comments**

Please offer any additional feedback your organization would like to provide on the final proposal and draft tariff language.

The tariff language limits the RAAIM exemption to only those DR resources with a Qualifying Capacity (QC) set by an ELCC or something “similar”. The tariff language gives CAISO sole discretion over whether an alternative methodology is similar enough to warrant a RAAIM exemption. Because the CEC stakeholder process is yet to commence, it is not clear the process will result in the same principles outlined by the CAISO in its Final Proposal. The working group may result in modifications to those principles or a new QC methodology that is not tied to an ELCC. As such, CalCCA makes the following recommended modifications to the draft tariff language:

> 40.9.2.b.1.(D) Demand Response Resources whose Qualifying Capacity is established using an effective load carrying capability methodology (as that term is used in Section 399.26(d) of the California Public Utilities Code, or a successor provision) or a methodology that the CAISO determines in ~~its sole discretion is substantially similar to the effective load carrying capability methodology~~ conjunction with the local regulatory authority effectively measures resource capability.

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

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| Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment. | R.17-06-026<br>(Filed June 29, 2017) |

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION, CENTRAL COAST COMMUNITY ENERGY, EAST BAY COMMUNITY ENERGY, PENINSULA CLEAN ENERGY, SILICON VALLEY CLEAN ENERGY AUTHORITY, AND CITY OF SAN JOSÉ, ADMINISTRATOR OF SAN JOSÉ CLEAN ENERGY'S APPLICATION FOR REHEARING OF DECISION 21-05-030**


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Silicon Valley Clean Energy Authority

June 23, 2021

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**Specification of Legal Error**

In adopting the Phase 2 Decision and rejecting key elements of the Working Group 3 proposal, the Commission:

- Failed to proceed in the manner required by law, as required by Public Utilities Code[1] Sections 1757(a)(2), 366.2(g), and 365.2, by failing to provide unbundled customers the full benefits of system and flexible RA in the IOUs' PCIA portfolios;

- Failed to meet the requirement of Section1757(a)(4) by rejecting the RA VAMO without substantial evidence in light of the whole record;

- Failed to proceed in the manner required by law, as required by Public Utilities Code Sections 1757(a)(2), 366.2(g) and 365.2, by failing to provide unbundled customers the full benefits of GHG-Free energy in the IOUs' PCIA portfolios;

- Failed to meet the requirement of Section 1757(a)(4) by rejecting the GHG-Free Energy allocation by ignoring substantial evidence in light of the whole record of the value of this product to unbundled customers;

- Abused its discretion contrary to Section 1757(a)(5) by encouraging a collaborative Phase 2 working group process but ignoring the collaborative work product; and

- Violated the due process rights of stakeholders who relied to their detriment on the Commission's directive to create consensus proposals based on working group discussion and analysis.

[1] All references herein are to the Public Utilities Code unless otherwise specified.

## TABLE OF AUTHORITIES

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### California Legislative Materials



### California Public Utilities Code



### California Public Utilities Commission Decisions



### California Public Utilities Commission Rules of Practice and Procedure

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

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| Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment. | R.17-06-026<br>(Filed June 29, 2017) |

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION, CENTRAL COAST COMMUNITY ENERGY, EAST BAY COMMUNITY ENERGY, PENINSULA CLEAN ENERGY, SILICON VALLEY CLEAN ENERGY AUTHORITY, AND CITY OF SAN JOSÉ, ADMINISTRATOR OF SAN JOSÉ CLEAN ENERGY'S APPLICATION FOR REHEARING OF DECISION 21-05-030**

The California Community Choice Association[2] (CalCCA), Central Coast Community Energy, East Bay Community Energy, Peninsula Clean Energy, Silicon Valley Clean Energy Authority, and City of San José, Administrator of San José Clean Energy (collectively, the "CCA Parties") submit this Application for Rehearing (Application) of Decision (D.) 21-05-030 (Phase 2 Decision), pursuant to Rule 16.1 of the California Public Utilities Commission's (Commission's) Rules of Practice and Procedure.[3] The Phase 2 Decision was voted out by the Commission on May 20, 2021 and issued on May 24, 2021.

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[2] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, 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, City of San José, Administrator of San José Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[3] Pursuant to Commission Rule 1.8(d) of the Commission's Rules of Practice and Procedure, Central Coast Community Energy, East Bay Community Energy, Peninsula Clean Energy, Silicon Valley Clean Energy, and City of San José, Administrator of San José Clean Energy, have authorized CalCCA to file this Application on their behalf.

## I. INTRODUCTION AND SPECIFICATION OF LEGAL ERROR

The Phase 1 Decision revising the Power Charge Indifference Adjustment (PCIA), D.18-10-019, directed a "working group" to "develop proposals regarding portfolio optimization and cost reduction for future consideration by the Commission" in Phase 2.[4] It further observed that "***allocation and auction*** mechanisms offer realistic and promising approaches to utility portfolio optimization and cost reduction."[5] The Scoping Ruling for Phase 2 directed these issues to be addressed by Working Group 3 (WG3), including "the structures, processes, and rules governing portfolio optimization that the Commission should consider in order to address excess resources in utility portfolios…."[6] The Scoping Ruling further tasked CalCCA, Southern California Edison Company and Commercial Energy (Co-Chairs) with leading and reporting the progress of the working group,[7] stating the Commission's expectation that parties will "work collaboratively."[8]

Following a lengthy and resource-intensive process, outlined in Section II below, the Co-Chairs presented a Final Report to the Commission chronicling the working group process and offering a recommendation based on the collaborative work product (WG3 Report).[9] The recommendations included voluntary allocation and market offer (VAMO)[10] processes, as contemplated by the Phase 1 Decision, for local, system, and flexible Resource Adequacy (RA) and Renewable Portfolio Standard (RPS) products. It further contemplated an allocation process

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4 D.18-10-019 (Phase 1 Decision), Conclusion of Law 26 at 159.

5 Phase 1 Decision, Finding of Fact 26 at 156 (emphasis supplied).

6 *Phase 2 Scoping Memo and Ruling of Assigned Commissioner*, Feb. 1, 2019 (Phase 2 Scoping Ruling) at 5.

7 *Id.* at 10.

8 *Id.* at 12.

9 *Final Report of Working Group 3 Co-Chairs: Southern California Edison Company (U 338-E), California Community Choice Association, and Commercial Energy*, Feb 21, 2021 (WG3 Report).

10 The WG3 Report used the term "Market Offer" rather than "auction" to refer to the potential sales frameworks, but both contemplate a sale of the PCIA resources to the highest bidder.

for greenhouse-gas free (GHG-Free) energy products.[11] These mechanisms aimed to minimize 366.2(g)resources in the PCIA portfolios by providing each customer – bundled and unbundled alike – proportional rights to "purchase" the products in the portfolio. In this way, the Co-Chairs anticipated that there would be no "excess" resources remaining in the portfolio, which resources would have been valued at zero.

Importantly, the mechanisms proposed in the WG3 Report achieve the stated goal of minimizing excess resources in a manner consistent with the statutes governing the PCIA. Through a "voluntary allocation" to both bundled and unbundled customers, the proposals contained in the WG3 Report would ensure unbundled community choice aggregator (CCA) customers receive the same rights as bundled customers to the full benefits of the products they fund through the PCIA, as required by Public Utilities Code Section 366.2(g). In turn, by providing CCA customers these benefits, the proposals would avoid violating the cost-shifting prohibition of Section 365.2; neither bundled nor unbundled customers would pay for benefits received by the other.

The Phase 2 Decision adopts some elements of the WG3 Report. The Phase 2 Decision also adopts the RPS VAMO mechanism proposed, recognizing the value of making this product proportionally available to load-serving entities (LSEs) serving unbundled customers. It declines, however, to provide unbundled customers *proportional* access to system and flexible RA products through the proposed RA VAMO. Likewise, it declines to provide unbundled customers *any* access to GHG-Free energy on a permanent basis by unnecessarily deferring the issue for a second time.

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[11] The GHG-Free energy proposal included only voluntary allocation, with no auction or market offer.

By rejecting the RA VAMO and GHG-Free energy allocation, the Phase 2 Decision commits legal error in several respects. The Phase 2 Decision:

- Fails to proceed in the manner required by law, as required by Public Utilities Code Sections 1757(a)(2), 366.2(g), and 365.2, by failing to provide unbundled customers the full benefits of system and flexible RA in the investor-owned utilities (IOUs') PCIA portfolios;

- Fails to meet the requirement of Section 1757(a)(4) by rejecting the RA VAMO without substantial evidence in light of the whole record;

- Fails to proceed in the manner required by law, as required by Public Utilities Code Sections 1757(a)(2), 366.2(g) and 365.2, by failing to provide unbundled customers the full benefits of GHG-Free energy in the IOUs' PCIA portfolios;

- Fails to meet the requirement of Section 1757(a)(4) by rejecting the GHG-Free Energy allocation by ignoring substantial evidence in light of the whole record of the value of this product to unbundled customers;

- Abuses its discretion contrary to Section 1757(a)(5) by encouraging a collaborative Phase 2 working group process but ignoring the collaborative work product; and

- 1757(a)(5) by encouraging a collaborative Phase 2 working group process but ignoring the resulting collaborative work product; and

- Violates the due process rights of stakeholders who relied to their detriment on the Commission's directive to create consensus proposals based on working group discussion and analysis.

On these grounds, the CCA Parties respectfully request rehearing of D.21-05-030.

## II. BACKGROUND

### A. The PCIA Framework

The PCIA was originally designed by the Commission to ensure that customers leaving utility procurement service to take service from Electric Service Providers under Direct Access (DA) did not leave bundled IOU customers holding the bag for high-priced resources procured in the past for all customers.[12] In particular, the PCIA was designed to enable the IOUs to recover

[12] *See generally* D.06-07-030; *see also* D.02-11-022, Conclusion of Law 21 at 158.

the high costs of resources procured during the Energy Crisis of 2000-2001.[13] The notion was that all customers – bundled and unbundled alike – would bear proportional responsibility for the above-market costs of these resources. The above market-costs would be netted against both the "value" to bundled customers of the resources they used, and the revenues received from the sale of resources not used by bundled customers.[14]

While the PCIA was originally conceived as a charge for DA customers, Assembly Bill 117 (2002)[15] established a similar construct for customers leaving IOU procurement to be served by CCAs. Section 366.2(f) imposes the costs of resources procured on behalf of CCA customers before leaving the IOU; Section 366.2(g) requires the Commission to either (i) offset costs with the value of the resources used by bundled customers or sold in the market or (ii) directly allocate the benefits of the resources to CCA customers.

The PCIA framework, until Phase 2, relied solely on the first option: offsetting costs with the value of the resources to bundled customers or revenues from market sales.[16] The "Market Price Benchmark" (MPB) became the valuation tool to meet the requirement of Section 366.2(g).[17] The Phase 1 Decision slightly modified this approach, offsetting the above-market costs by the MPB for resources retained by the bundled customers but by actual market revenues for all other resources or attributes.[18]

Although none of the benefits of the above-market resources in the IOUs' portfolios have historically been directly conferred to CCA customers pursuant to Section 366.2(g), the Phase 1 Decision took a step down this path. As discussed in Section II.B. below, the Commission

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13 *See generally* D.02-11-022.

14 D.06-07-030, Ordering Paragraph 16 at 59-62.

15 Assembly Bill 117 (Stats. 2002, ch. 838).

16 *See, e.g.*, D.06-07-030, Ordering Paragraph 16 at 59-62; the Phase 1 Decision.

17 *See generally* Phase 1 Decision.

18 *Id.*, Conclusion of Law 16 at 157-158.

contemplated that as a means of portfolio optimization and reducing costs, "allocation" of PCIA resources should be considered.[19] The Commission stated: "***allocation*** and auction mechanisms offer realistic and promising approaches to utility portfolio optimization and cost reduction."[20]

Based on this directive, WG3 headed down the path of developing an allocation and auction or "market offer" proposal as an alternative to valuation under Section 366.2(g). Indeed, the WG3 Report proposes making the products and attributes available directly to departing load customers as an alternative to direct valuation. In short, the use of allocation became a focal point of Phase 2.

### B. Phase 2 Procedural History

After more than a year of activity, including oral argument and cross examination of witnesses, briefs, and numerous rounds of detailed party comments, the Commission issued D.18-10-019 in Phase 1 in October 2018 (Phase 1 Decision). The Phase 1 Decision resolved benchmark-related issues affecting the calculation of the PCIA calculation. But the Commission deferred important issues raised by parties to a second phase of the proceeding:

> The second phase's purpose is to develop structures, processes, and rules governing portfolio optimization going forward . . . The second focus of phase two will be to minimize further accumulation of uneconomic costs. . . . Phase two will also consider shareholder responsibility for future portfolio mismanagement, if any, so that neither bundled nor departing customers bear full cost responsibility if utilities do not meet established portfolio management standards.[21]

The Phase 1 Decision directed a "working group" to "develop proposals regarding portfolio optimization and cost reduction for future consideration by the Commission."[22] As noted above,

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19 *Id.*, Finding of Fact 26 at 156.
20 *Id.*, (emphasis supplied).
21 *Id.* at 111-112.
22 *Id.*, Conclusion of Law 26 at 159.

the Commission also observed that both ***allocation and auction*** mechanisms merited further enquiry.[23]

The Scoping Ruling for Phase 2 directed these issues to be addressed by WG3. The ruling further tasked the Co-Chairs with leading and reporting the progress of the working group,[24] stating the Commission's expectation that parties will "work collaboratively."[25]

The Co-Chairs conducted a lengthy and resource-intensive working group process. As the WG3 Report summarizes, the process involved thousands of hours contributed by stakeholders and Co-Chairs.[26] Their activities included more than 60 Co-Chair regular meetings, with meetings twice a week for the last three to four months leading up to the submission of the WG3 Report. The Co-Chairs conducted four stakeholder workshops in 2019, either in person or by phone, with three in San Francisco and one in Southern California. The Co-Chairs sought stakeholder comments after each workshop and provided opportunities for stakeholders to make presentations. The Co-Chairs submitted two progress reports in 2019, on June 24 and September 26. Then, on February 21, 2020, the Co-Chairs submitted the WG3 Report, summarizing the full course of the process and parties' positions, accompanied by a recommendation supported by Co-Chair consensus. Parties also filed opening and reply comments on the WG3 Report, on March 13, 2020, and March 27, 2020. Finally, Southern California Edison Company (SCE) maintained a Sharepoint site as a repository of materials (workshop materials, Co-Chair work plan, meeting agendas, etc.) available to all parties.

23 *Id.*, Finding of Fact 26 at 156 (emphasis supplied)
24 Phase 2 Scoping Ruling at 10.
25 *Id.* at 12.
26 WG3 Report at 12-14.

The WG3 Report presented proposals for portfolio optimization and cost reduction as directed by the Phase 1 Decision and the Scoping Ruling.[27] The recommendation included VAMO[28] processes, as contemplated by the Phase 1 Decision, for local, system, and flexible RA and RPS products. It further contemplated an allocation process for GHG-Free energy products. These mechanisms aimed to minimize resources in the PCIA portfolios by providing each customer – bundled and unbundled alike – proportional rights to "purchase" the products in the portfolio. In this way, the Co-Chairs anticipated that there would be no "excess" – i.e., no unsold or unallocated – resources remaining in the portfolio. This was important to avoid the "zero" valuation of these resources in calculating the PCIA, as directed by D.19-10-001.[29]

The mechanisms proposed in the WG3 Report achieve the stated goal of minimizing excess resources in a manner consistent with the statutes governing the PCIA. Through a "voluntary allocation" to both bundled and unbundled customers, the WG3 Report proposals intended to ensure that unbundled CCA customers and bundled customers alike receive the full benefits of the products they fund through the PCIA, as required by Section 366.2(g). In turn, by providing CCA customers these benefits, the WG3 Report proposals would avoid violating the cost-shifting prohibition of Section 365.2 because neither bundled nor unbundled customers would pay for benefits received by the other.

Following the receipt by the Commission of comments on the WG3 Report, concluding on March 27, 2020, no further action was taken by the Commission until the issuance of a proposed decision more than a year later, on April 5, 2021.

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27 *See generally* WG3 Report.

28 *See* WG3 Report at 16. The WG3 Report used the term "Market Offer" rather than "auction" to refer to the potential sales frameworks, but both contemplate a sale of the PCIA resources to the highest bidder.

29 *See* D.19-10-001, Ordering Paragraph 3.b. at 56 (adopting a zero value for unsold RPS), and Ordering Paragraph 3.e. at 56 (adopting a zero value for unsold RA).

## III. THE PHASE 2 DECISION VIOLATES PUBLIC UTILITIES CODE SECTIONS 366.2(g) AND 365.2 BY FAILING TO PROVIDE TO UNBUNDLED CUSTOMERS THE FULL BENEFITS OF RESOURCE ADEQUACY AND GHG-FREE RESOURCES IN THE IOUS' PCIA PORTFOLIOS

The Phase 2 Decision violates Public Utilities Code Section 366.2(g), which guarantees CCA customers the full benefit of the resources for which they bear cost responsibility through the PCIA charge. CCA customers, like IOU bundled customers, pay equally for the RA and GHG-Free products in the PCIA portfolio; the Phase 2 Decision, however, provides only bundled customers preferential access to RA products and *no* access to GHG-Free energy on a long-term basis. By effectively requiring unbundled customers to pay equally for benefits only bundled customers receive, the Phase 2 Decision also violates the Section 365.2 prohibition against cost-shifting among unbundled and bundled customers. Consequently, and contrary to Section 1757(a)(2), in issuing this decision, the Commission has not "proceeded in the manner required by law."

### A. Sections 366.2 and 365.2 Require the Commission to Provide Both Bundled and Unbundled Customers the Benefit of IOU Portfolio Resources Purchased on Their Behalf and Thereby Avoid Cost Shifts Between These Customers

Sections 366.2(g) and 365.2 work together to ensure that *all* IOU bundled customers *and* departed load customers get what they pay for. Section 366.2(g) requires that:

> [e]stimated net unavoidable electricity costs paid by the customers of a [CCA] shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the [CCA] are allocated a fair and equitable share of those benefits.[30]

As a result, the Commission may provide CCA customers either an offset against costs for the value of the resources retained by the IOU or "a fair and equitable share of those benefits."

[30] Cal. Pub. Util. Code § 366.2(g).

Similarly, Section 365.2 is intended to prevent inequitable cost shifting between IOU bundled customers and departed customers:

> The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.[31]

This cost shift occurs, for example, if the benefits retained by bundled customers are not accurately valued, such that departed load costs increase beyond their proportional share of PCIA portfolio costs. Both statutes bear directly on the Commission's rejection of key proposals in the WG3 Report, as discussed below.

### B. In Rejecting the WG3 Proposals, the Commission Fails to Comply with Sections 366.2(g) and 365.2

WG3 developed its proposals to achieve compliance with Sections 366.2(g) and 365.2. The direct allocation of the benefits from the IOUs' portfolios would ensure that all customers – bundled and unbundled – receive their proportional share of benefits, thus averting a cost shift between customers.

All customers – bundled and unbundled – pay the above-market costs of the PCIA portfolio in proportion to their vintaged load shares. Consequently, the Commission must provide unbundled customers their proportional benefits from the portfolio, either by (i) a direct allocation of the benefits or by (ii) valuing the benefits provided to bundled customers and crediting that value against stranded costs. Until Phase 2, the Commission attempted to take the latter route, creating MPBs to establish values for benefits provided to bundled customers. The

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[31] *Id.*, § 365.2.

WG3 Report proposals, taking a cue from the Phase 1 Decision's directive to consider "allocation," pursue the former route of in-kind benefits.

It is possible to use either approach to balance benefits between bundled and unbundled customers; the direct allocation route, however, captures more of the value of the PCIA products – in particular, preferential access or the "right of first refusal" to these products. Critically, in the context of the Phase 2 Decision, the direct allocation route is the only way to achieve the goal of minimizing excess resources in the PCIA portfolios while ensuring that the benefits are proportionally shared as required by Section 366.2.

The WG3 Report contains a framework attributing portfolio resources to those customers paying for them. After considering an "excess sales approach" versus an "allocation based approach" to reducing excess resources in the PCIA portfolios, WG3 chose the allocation approach for each PCIA-eligible LSE "based upon the proportional share of the IOU's entire-PCIA eligible, vintaged position."[32] As stated in the WG3 Report, "allocations ensure that all attributes are appropriately distributed among all LSEs, so their customers are able to realize the value they are paying for."[33] The intent of the WG3 Report is therefore to confer upon all customers who pay the PCIA the <u>full benefits</u> of the PCIA-resources, as required by Sections 366.2(g) and 365.2.

In denying CCA customers access to the RA and GHG-Free Energy resources as proposed by WG3, the Commission retains the status quo that has proved unworkable and in fact violates state law. As discussed below, the Phase 2 Decision denies unbundled customers preferential access to their proportional share of RA resources and denies them *any* access to their share of the value of the GHG-Free attribute of certain energy resources. Without clear

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32 WG3 Report at 15.

33 *Id.*

explanation, the Phase 2 Decision adopts the same VAMO structure for RPS resources, implicitly acknowledging the value of this mechanism. The Phase 2 Decision will result in unbundled CCA customers paying for both RA benefits and GHG-Free Resources for which they receive inadequate cost reduction and insufficient benefit, violating the prohibition in Section 365.2 against cost shifting.

#### 1. The Phase 2 Decision Fails to Provide the Benefit of Preferential Access to RA in the PCIA Portfolio Despite Its Clear Recognition of Value

To properly distribute the inherent value of preferential access to IOU RA resources, which is currently held by bundled customers only, the WG3 Report included a voluntary allocation to LSEs of each IOU's system and flexible RA resources, followed by a market offer of unallocated amounts (RA VAMO). In addition to conforming with existing law, the aim was to minimize the amount of "excess" – unsold – resources left in the IOU portfolios and valued at zero. However, in the Phase 2 Decision the Commission determined that it "do[es] not have sufficient evidence of an observable and verifiable 'right of first refusal' benefit retained by bundled customers that would justify modifying PCIA calculations or requiring allocations of [RA] resources."[34] CalCCA described the preferential access bundled customers, through the IOUs, enjoy to the IOUs' portfolio's RA resources as a "right of first refusal" (ROFR). As CalCCA explained, this term simply describes the ability of each IOU (for the benefit of its bundled customers) to use existing RA resources for compliance. That such ability currently resides with the IOUs for the benefit of their bundled customers is uncontroverted and is, in fact, reinforced by the Phase 2 Decision.

[34] Phase 2 Decision at 43.

Whatever name is applied to this right, the Commission clearly recognized the inherent value such preferential access confers on the IOU and its bundled customers. For example, the Commission cites to Pacific Gas and Electric Company's (PG&E's) concerns that, if adopted, the RA VAMO "would leave PG&E with insufficient resources to meet bundled customer needs and would increase electric portfolio costs for bundled service and departing load customers alike."[35] Thus, the IOU implicitly asserts, and the Commission apparently agrees, that the IOU's bundled customers' needs are preeminent. It is obvious the bundled customers' position as "first in line," whatever name is used to describe it, has value; otherwise, the Commission would not have reserved this right for bundled customers.

PG&E's concern points to another issue. Although the MPB was intended to reflect market prices, the Commission has tacitly admitted that if RA resources were proportionally allocated, PG&E would need to acquire more RA for compliance purposes and would likely face prices that are higher than the actual benchmark. If requiring the IOUs to go into the market to procure RA resources for bundled customers will *increase* their costs, then it follows that the MPB is *below* actual market prices. If the MPB is a fair representation of market prices, all customers, including bundled customers, should be indifferent to paying the MPB or market prices. The fact that the Commission agrees with PG&E's stated concerns actually confirms that there is definite value in being "first in line."

Whether that value can be quantified, and whether it is currently accounted for in the PCIA methodology, are separate and difficult questions. It is precisely because of this difficulty the WG3 Co-Chairs devised the VAMO process for system and flexible RA resources. In order

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[35] *Id.* at 44, citing *Opening Comments of Pacific Gas and Electric Company (U 39 E) on the Power Charge Indifference Adjustment Phase 2, Working Group #3 Final Report,* Mar. 13, 2020 (PG&E's WG3 Proposal Opening Comments).

to achieve a fair distribution of the value inherent in the bundled customers' current "first in line" position, these RA resources – and that concomitant "first in line" position – should be subject to proportional allocation among LSEs.

### 2. The Phase 2 Decision Fails to Provide Any Benefits of GHG-Free Resources in the PCIA Portfolio

In addition to failing to provide CCA customers with the benefit of preferential access to their proportional share of RA resources, the Phase 2 Decision also fails to order the allocation of benefits of GHG-Free Resources in the PCIA portfolio to unbundled customers.[36] The Commission had previously rejected CalCCA's proposal in Phase 1 of this proceeding that would have recognized the value of GHG-Free energy through a credit in the PCIA calculation.[37] The Commission rejected the proposal, due largely to the lack of robust market price data to provide a reference value, but also invited further consideration of this issue.[38] The WG3 Proposal, therefore, provided an alternative method to value GHG-Free energy through a direct allocation to unbundled customers. The value of GHG-Free energy to LSEs was explained in the WG3 Report as being able to show "GHG-free energy procurement on an LSE's [Power Content Label with the California Energy Commission] and for planning purposes in the IRP."[39]

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[36] The Commission found that it "do[es] not have a sufficient record to support adoption or rejection of the WG3 Proposal or an alternate proposal at this time. We will consider as a next step in this proceeding whether GHG-Free resources are under-valued in the PCIA methodology, and whether to adopt a GHG-Free adder or an allocation mechanism." Phase 2 Decision at 54.

[37] *See* Phase 1 Decision at 148.

[38] *Id.* at 150-52.

[39] WG3 Report at 30-32.

### a. Approval and Extension of the Interim Allocation Acknowledges that GHG-Free Resources Have Value

The Commission approved the requests of SCE and PG&E to implement interim GHG-Free energy allocations to LSEs pending the outcome of Phase 2.[40] These allocations are substantially similar to the WG3 Proposal.[41] In addition, the Phase 2 Decision *extends* the SCE interim allocation for an additional year.[42] These actions tacitly acknowledge the value in making GHG-Free Resources available proportionally to all LSEs. Indeed, stakeholders recognize this value, as well. During the period January 1 through December 1, 2020, nineteen contracts for GHG-Free energy sales were entered into between PG&E and various LSEs pursuant to PG&E's interim allocation.[43] Notwithstanding the Commission's recognition of the value of GHG-Free Resources by approving these interim measures, the Commission then ignores this recognition by rejecting the permanent GHG-Free allocation proposed by the WG3 Proposal and deferring the issue to another phase.

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40 *See* Resolution E-5046 (approving PG&E's proposal to make one-year allocations of nuclear and hydroelectric resources available to LSEs in 2019 and 2020); Resolution E-5111 (extending PG&E program through 2023); Resolution E-5095 (approving SCE's interim program).

41 *See* PG&E Advice Letter (AL) 5705-E, Dec. 2, 2019 (adopted by Commission Resolution E-5046, in which PG&E sought to add Appendix P to its Bundled Procurement Plan (BPP) allowing LSEs to be eligible to purchase "Carbon Free Energy" from nuclear and large hydroelectric resources in PG&E's portfolio because "[p]arties in the PCIA proceeding have raised the issue of how the value of GHG free resources that have their above market costs recovered through the PCIA should be optimized and subsequently reported for the California Energy Commission's (CEC) Power Content Label…" and "PG&E developed Appendix P (Carbon Free energy) to address these issues…"); *see also* SCE AL 4194-E, Apr. 17,2020 (adopted by Commission Resolution E-5095, in which SCE, submitting the advice letter jointly with Clean Power Alliance, proposes to add a Tariff Sheet to SCE's BPP that enables LSE's operating in SCE's service territory whose customers pay the PCIA and CTC to receive allocations of GHG-Free energy at no additional cost from SCE's bundled portfolio as an interim mechanism until the Commission adopts a permanent allocation mechanism).

42 Phase 2 Decision, Ordering Paragraph 12 at 67.

43 *PG&E Application for Compliance Review of Utility-Owned Generation Operations, Portfolio Allocation Balancing Account Entries, Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility-Owned Generation Fuel Procurement, and Other Activities For the Period January 1 Through December 31, 2020, Prepared Testimony*, Mar. 1, 2021, at 9-10, 9-11, and Table 9-1.

**b. Notwithstanding Recognition of the Value of GHG-Free Resources, the Commission Fails to Provide Unbundled Customers Any GHG-Free Benefits**

The Phase 2 Decision states that it does not have sufficient evidence of heightened market value for GHG-Free Resources at this time, and therefore postpones consideration of the allocation of GHG-free resources to the next step in this proceeding. However, the Phase 2 Decision accepts the argument of CalAdvocates that allocating GHG-Free energy to all customers would "result in higher rates for bundled customers."[44] By stressing the value of allowing bundled customers to retain these GHG-Free resources, the Phase 2 Decision therefore confirms that GHG-Free energy confers a distinct value. Again, as with the RA allocations, this means that the current MPB methodology, which does not include a GHG-Free energy value, is understating portfolio value and benefitting bundled customers at unbundled customers' expense. The Commission therefore again fails to allow the proportional allocation of PCIA resource benefits to avoid having bundled customers face higher rates, thereby implicitly increasing the cost to unbundled customers. In this way, the Commission consistently and unlawfully fails to adopt the allocation of benefits to unbundled customers required by Section 366.2(g), which also results in unlawful cost shifting pursuant to Section 365.2.

**c. Contrary to PG&E's Claim, GHG Emitting Resources Provide No "Benefits" Beyond the Brown Power Value Already Litigated and Recognized in the Market Price Benchmark**

One of the justifications in the Phase 2 Decision for not adopting the WG3 GHG-Free allocation is PG&E's concern that PCIA-eligible LSEs should be required to take their combined share of both GHG-Free and GHG-emitting resources.[45] The Phase 2 Decision fails to recognize, however, that GHG-emitting resources provide no "benefits" to LSEs beyond the "brown power"

44 Phase 2 Decision at 51.
45 *Id.* at 52.

value that has already been litigated, and is currently recognized in the MPB. In addition, PG&E does not identify any additional "benefit" that requires allocation under Section 366.2(g). Therefore, the Commission cannot lawfully rely on this argument in rejecting the GHG-Free allocation.

#### d. An In-Kind Allocation of GHG-Free Energy Does Not Require a Quantified Value, Unlike a GHG-Free Adder to the MPB

While deferring the GHG-Free allocation to the "next step in this phase of this proceeding," the Commission states that it will consider "whether GHG-Free resources are under-valued in the PCIA methodology, and whether to adopt a GHG-Free adder or an allocation mechanism."[46] The Commission fails to recognize, however, that an in-kind allocation of GHG-Free Energy through allocation does not require a quantified value, unlike a GHG-Free adder to the MPB. The value of access to these products is implicitly captured in the right to receive a proportional allocation from the PCIA portfolio; if there is value, presumably customers will take their allocation, if there is no value, they will not.

### C. The Commission Must Grant Rehearing of the Phase 2 Decision Based on Its Failure to Proceed in the Manner Required by Law

The Phase 2 Decision's rejection of the RA and GHG-Free allocations to unbundled customers results in the Commission unlawfully adopting policies that allow a ROFR benefit to IOU bundled customers of access to RA and GHG-Free resources. Such policies violate Section 366.2(g) and its guarantee that unbundled CCA customers receive the benefits that they pay for in the PCIA, as well as Section 365.2 and its prohibition of unlawful cost shifting from unbundled to bundled customers. For these reasons, the Commission should grant rehearing of

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[46] *Id.* at 54.

the Phase 2 Decision and adopt the proportional allocation of RA and GHG-Free resources among bundled and unbundled customers.

## IV. THE DECISION'S UNDERLYING REASONING FOR REJECTING THE WG3 PROPOSALS REGARDING RA AND GHG-FREE EMISSIONS IS NOT SUPPORTED BY EVIDENCE, PRIOR COMMISSION DECISIONS, OR LOGIC

The Phase 2 Decision is unsupported by the substantial evidence in the record, prior Commission decisions, or logic. The determination that any allocations must be limited to quantities exceeding bundled customer needs is not supported by the Phase 1 Decision. Second, the Commission's rejection of the RA VAMO based on its claim of the similarity to the proposal rejected in the Phase 1 Decision regarding the "inherent hedge and option value" in the MPB is erroneous based on the record. Third, the Commission's rejection of the system and flexible RA VAMO based on the existence of the new CPE for local RA is erroneous given the irrelevance of the CPE to system and flexible RA. Finally, the Commission's sweeping conclusions regarding the market, rate, planning, and compliance impacts of the RA VAMO are unsupported by substantial evidence in the record. As these erroneous determinations by the Commission are not "supported by substantial evidence in light of the whole record" as required by Section 1757(a)(4), rehearing must be granted.

### A. The Decision's Conclusion That an Allocation Must Be Limited to Quantities Exceeding Bundled Needs is Not Justified or Supported by the Phase 1 Decision

Notwithstanding the clear intent of the Phase 1 Decision, the Commission inexplicably and illogically denies WG3's proposals regarding RA and GHG-Free resources. The Commission mistakenly determines that insufficient evidence has been presented to establish the Commission's goal of reducing "excess and/or uneconomic resources." The Commission also mistakes how to define such "excess" resources, which the Commission determines are only those "resources that are not necessary to meet bundled customers' needs and compliance requirements."[47] These determinations are unsupported by substantial evidence.

The Commission erroneously adds a "standard of review" to proposals under Phase 2 that first requires the proponent to submit evidence of "excess and/or uneconomic resources" in the IOUs' portfolios. This was never envisioned in the Phase 1 Decision's direction for the next phase of the enquiry. In fact, this is contrary to the presumption underlying Phase 2 itself – that there exist resources in the IOUs' portfolios that are uneconomic, and that are neither needed for compliance or desired by the market. The Commission misapplies prior Commission decisions by permitting under its new standard of review for Phase 2 only those solutions that deal exclusively with these "excess and/or uneconomic" resources. This standard of review includes a tautology the Co-Chairs identified and sought to redress: it begs the question of what resources fit the Commission's new definition of "excess resources" as "resources that are not necessary to meet bundled customers' needs and compliance requirements."[48] If it were straightforward to establish those "needs," WG3 would not have proceeded with the allocation and market offer constructs it developed. This tautology reveals the Commission's error in interpreting the Phase 1 Decision. In denying the WG3 Reports' solutions for RA and GHG-Free resources, the Commission fails to achieve the goal of this proceeding.

#### 1. Contrary to the Commission's Conclusion, the Phase 1 Decision <u>Assumed</u> Excess and Uneconomic Resources Exist in IOUs' Portfolios

The Phase 2 Decision states that as an initial matter the Commission must "consider whether the RA proposal advances the goal of reducing excess and/or uneconomic resources in utilities' PCIA portfolios. Parties did not provide sufficient evidence in this proceeding to

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47 Phase 2 Decision at 14.
48 *Ibid*.

establish whether each IOU will have excess and/or uneconomic resources."[49] This statement directly contravenes the Phase 1 Decision.

In the Phase 1 Decision the Commission initiated the second phase precisely because it assumed the existence of "excess and/or uneconomic resources." The Commission stated the goals of Phase 2: "We are initiating a second phase of this rulemaking that offers the promise of meaningful progress toward reducing the levels of above-market costs going forward."[50] Further, the Commission explicitly stated its recognition "that parts of the IOU portfolio are in excess of bundled customers' needs," such that "phase two of this proceeding will work toward portfolio optimization and cost reduction."[51] Finally, the Commission flatly affirmed the existence of uneconomic costs, stating: "The second focus of phase two will be to minimize further accumulation of uneconomic costs." (emphasis supplied) [52] Inexplicably, the Commission now requires there to be "evidence" of these excess and/or uneconomic costs.

### 2. Not Even PG&E Demonstrates That It Has No Excess or Uneconomic Resources in the PCIA Portfolio

Not only does the Commission overthrow the Phase 1 Decision by now requiring "evidence" of these excess resources, it goes even further. The Commission defers to untested and unverified statements from PG&E to find that there are, in fact, no "excess resources" to deal with. The Commission actually justifies the denial of the RA elements of the WG3 Report based on PG&E's comments, which "indicate that it will not have excess resources."[53] Although the statement strains credulity and contradicts the Commission's findings in Phase 1, the Commission simply defers to PG&E's explanation "that it has actively managed its RA portfolio

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49 *Id.* at 41.
50 Phase 1 Decision at 129.
51 *Id.* at 50.
52 *Id.* at 112.
53 Phase 2 Decision at 41.

to sell excess products in response to departed load, and also considered forecasted load departure in determining incremental procurement quantities."[54] Significantly, PG&E has not provided any "evidence" of its claims, yet the Commission accepts these claims without question.

### 3. The Decision Incorrectly Applies the Phase 1 Decision to Require a Solution Based Solely on the Allocation of Resources in Excess of Bundled Customer Requirements

Referring to the Co-Chairs' proposals to allocate IOU PCIA-eligible resources to other LSEs to the extent such are "excess to the bundled customers' share of the portfolio," the Commission determines, without justification, that "CalCCA's interpretation of 'excess resources' conflicts with the plain language of our decision."[55] This determination misconstrues the Phase 1 Decision.

The Commission apparently bases its conclusion on this statement taken out of context from the Phase 1 Decision: "[r]ecognizing that parts of the IOU portfolio are *in excess of bundled customers' needs*, Phase two of this proceeding will work toward portfolio optimization and cost reduction" (emphasis supplied).[56] The Commission mistakenly uses this phrase to define as "excess," and therefore subject to any proposed solution to come out of Phase 2, as "excess to bundled customers' needs." The Commission thereby imposes a limitation on the type of solutions that may be implemented through Phase 2. The Commission's decision is faulty. Nothing in the Commission's prior decision regarding what resources would be considered for Phase 2 limits those resources only to "excess."

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54 *Ibid*.

55 *Id*. at 12.

56 *Id.*, quoting Phase 1 Decision at 59.

In addition, the Commission's focus on this "plain language" ignores numerous other references in the Phase 1 Decision, and more importantly a Conclusion of Law, that "excess resources" encompass all of an IOU's PCIA-eligible resources. The "plain language" that excess resources "are in excess of bundled customer needs" appears only once in the Phase 1 Decision in a section discussing the ratemaking treatment of legacy utility-owned generation (UOG).[57] It is this one reference, appearing in a section of the decision unrelated to the issue of allocation, that the PD extrapolates to the entirety of the Phase 1 Decision.[58]

In other parts of the decision, however, the Phase 1 Decision clearly uses the term "excess resources" to refer to all of the IOU's PCIA-eligible resources. For example, in rejecting the Joint Utilities' proposal in which all of the IOU's "RA and [renewable energy credit] REC attributes are allocated pro rata to the LSEs serving departing load customers,"[59] the Phase 1 Decision described this approach as offering to resolve the issue of "excess resources in the Joint Utilities' portfolios to serve a declining customer base."[60] Similarly, when describing Commercial Energy's Voluntary Allocation and Auction Clearinghouse (VAAC) proposal (discussed further below) which also would have proportionately allocated all of the IOU's resources (not just excess), the Phase 1 Decision once again described this proposal as replacing the MPB "with other means of valuing the excess resources in the portfolios"[61] of the IOUs and that it "encourages LSEs to participate and accept or bid for excess IOU's resources."[62]

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57 Phase 1 Decision at 59.

58 The phrase "excess resources" appears 22 times in the Phase 1 Decision. In addition to the excerpts cited in these comments there are two references to the treatment of "excess resources" in truing-up the MPB (at 123 and 137); two regarding the issue of securitization (at 100); eight times in direct citations to other parties (at 18, 22, 24, 54, 57, 67, and 100) and twice regarding Commercial Energy's proposal, which proposed a proportional allocation of all of the IOU's resources (at 20, 22).

59 Phase 1 Decision at 91.

60 *Id*. at 93-94.

61 *Id*. at 20.

62 *Id*. at 22.

Equally important, while the Phase 1 Decision refers to a follow-up proceeding to address "excess resources," it is again not defined.[63] Indeed, the need to address "excess resources" in Phase 2 is not even carried over to any of the Findings of Fact, Conclusions of Law, or Ordering Paragraphs. The Phase 1 Decision's guidance for Phase 2 was "to consider proposals for a 'working group' process to enable parties to continue working together to develop proposals regarding portfolio optimization and cost reduction for future consideration by the Commission."[64] It contained no mention of the term "excess resources." It is only later in the Phase 2 Scoping Ruling that the direction to focus on "excess resources" again appears, [65] and once again is never defined.

Further support for the contention that the Phase 1 Decision's understanding of the term "excess resources" was sufficiently broad enough to encompass all of the IOU's resources can be seen from the decision's unique treatment of Commercial Energy's VAAC proposal. The Phase 1 Decision specifically called out this proposal for further development in a Conclusion of Law.[66] It is unclear how this Conclusion of Law could be implemented without "excess resources" being defined broadly consistent with Commercial Energy's proposal "[a]s applied to the PCIA context… that the first step be a voluntary allocation to LSEs of <u>all</u> PCIA-eligible IOU resources"[67] with the next step "a voluntary auction of the remaining resources."[68] As the VAAC proposal was based on the Commission's own treatment of Core Transport Agents (the natural gas version of CCAs) being eligible for a proportional allocation of <u>all</u> of the natural gas

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63 *Id*. at 3, 71.
64 *Id.*, Conclusion of Law 26 at 159.
65 Phase 2 Scoping Ruling at 5.
66 Phase 1 Decision, Conclusion of Law 8 at 157.
67 *Opening Brief of Commercial Energy of California*, June 1, 2018, at 4 (emphasis supplied).
68 Phase 1 Decision at 22.

IOU's resources, an approach the Commission approved in its Gas Accord V decision,[69] the Commission would have been well aware of the proposed mechanics to allocate all of the IOU's resources.[70]

Accordingly, the Commission erred in concluding that the Phase 1 Decision precluded the Commission's consideration of an allocation of all resources in Phase 2. Ironically, the Commission itself did not feel bound by this restriction with respect to RPS, choosing to allocate all of the IOU's PCIA eligible RPS resources. Why this restriction applies to RA and GHG-Free resources, but not to RPS resources, is unexplained.

Finally, in discussing the excess standard it has just imposed, the Commission actually notes that at any given time "effective solutions with the foregoing [required] attributes may result in disposition of more or less resources than the excess amount needed to serve bundled customers' needs over time."[71] Thus, inconceivably, even the Commission apparently realizes limiting solutions to its narrow definition of "excess" excludes potential workable and effective solutions.

### B. The Decision Erroneously Rejects the RA VAMO on Grounds That a Similar Proposal For Including an "Option" or "Hedge" Value in the Market Price Benchmark Was Denied in the Phase 1 Decision

In the Phase 1 Decision the Commission grappled with the issue of whether, or how to, incorporate the "inherent hedge and option value" in long-term contracts in the brown power market price benchmark, and ultimately decided not to attempt including this value in the benchmark.[72] In the Phase 2 Decision, the Commission claims the same arguments exist with

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69 D.11-04-031, Finding of Fact 27 and Ordering Paragraph 1 at 66, 72.
70 Appendix A to the Gas Accord provides a numerical example of how this process works which is almost identical to the VAMO process proposed by the working group.
71 Phase 2 Decision at 12.
72 Phase 1 Decision at 35.

respect to the "option" or "hedge" value that CalCCA has continued to argue should be recognized in the IOUs' RA portfolios.[73] Because the situations are entirely dissimilar, the Commission errs in rejecting the RA VAMO on these grounds.

As noted, the question in the Phase 1 Decision was whether the current market price benchmark for brown power adequately takes into account the inherent value of long-term positions. Assigning value to this attribute gave the Commission difficulty, and it ultimately decided it could not quantify this value to "bake it in" to the benchmark.

The current question, however, is not the "value" of an option, but whether *an allocation* of RA should be attempted. Indeed, a significant benefit of an allocation process is that it removes the need for precise quantification of the value of the attribute. If there is no value, then there is no loss to bundled customers. If there is a value, then this value must be shared proportionally with unbundled customers. Instead of struggling with how to recognize and properly quantify the inherent value of existing long RA positions, the allocation put forward by the Co-Chairs would simply transfer a portion of those positions to LSEs that have a right to such allocation value.

### C. The Existence of a CPE for Local RA Is Irrelevant and Should Have No Effect on the Adoption of a System and Flexible RA VAMO

The Phase 2 Decision concludes that the RA elements of the WG3 Report are "not properly tailored" to minimize the risks of unintended consequences, particularly "when layered with the new [Central Procurement Entity (CPE)] and RA compliance requirements."[74] The Commission seems focused on the fact that the WG3 Proposal "does not consider the potential

73 Phase 2 Decision at 42.
74 *Id*. at 43.

impact of a CPE on Local RA procurement.  Neither does the WG3 Proposal recommend how to make its RA proposal compatible with the new CPE." [75]

The response to the Commission's concern is simple:  the new CPE for local RA procurement in PG&E and SCE service territories approved in D.20-06-002 does not apply to either system or flexible RA.  Thus, whether or not the new CPE addresses, as the Commission would have it, "many of the concerns the WG3 co-chairs raised about RA procurement,"[76] the CPE simply does not address any concerns regarding system or flexible RA at all.

Whether or not the WG3 Report properly "considered" the impact of the yet-to-be-adopted CPE is completely irrelevant.  The CPE, in fact, is irrelevant to the continuing issues posed by the distribution of system and flexible RA among LSEs, and the market power and cost and compliance implications the WG3 Report addresses.  The Commission errs in claiming the existence of the CPE provides grounds for denial of the proposals in the WG3 Report as they relate to system and flexible RA.

### D. The Decision's Vague and Sweeping Conclusions Regarding the Market, Rate, Planning, and Compliance Impacts of the RA VAMO Are Unsupported by Substantial Evidence as Required by Section 1757(a)(4)

Grounds for review of a Commission decision include whether "the findings in the decision of the commission are not supported by substantial evidence in light of the whole record."[77]  Notwithstanding the Phase 2 Decision's emphasis on verifiable "evidence" elsewhere, the Commission makes broad, conclusory statements regarding the market, rate, planning, and compliance impacts of the RA VAMO.  The Phase 2 Decision thus fails this standard.

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[75] *Ibid.*

[76] *Ibid.*

[77] Cal. Pub. Util. Code § 1757(a)(4).

In rejecting the WG3 Proposal for the RA VAMO, the Commission notes it has considered "whether the proposal is tailored to minimize the risk of unintended consequences."[78] The Commission then notes PG&E's unsupported claims that implementing VAMO would leave PG&E with insufficient resources to meet bundled customer needs and would increase electric portfolio costs for all customers."[79] The Commission also cites AReM/DACC's, again unsupported, claims that it "could also require LSEs to accept Local RA that they do not need, resulting in inefficiencies and over-procurement."[80] The Commission also notes with approval PG&E's audacious claims, not coupled with any evidence, that the WG3 Proposal would create a "significant and unprecedented market, regulatory, and planning transformation" that would open 80 percent of its portfolio for allocation, increase costs for bundled and departing customers alike, require PG&E to procure additional resources for RPS and RA compliance, and increase IOU system and administrative costs.[81]

Significantly, *none* of these claims are supported by any of the "evidence" the Commission has required elsewhere. Nonetheless, the Commission places full reliance on these statements as justification for denying the proposals in the WG3 Report. It is striking to contrast the Commission's acceptance of these statements with its treatment of the WG3 proposals themselves. The Commission rejects CalCCA's position on the inherent "hedge" value of the right of first refusal because "[a]s in D.18-10-019, we are left to base our decision on what we are able to observe and verify. . . . . We do not have sufficient evidence of an observable and verifiable 'right of first refusal' benefit retained by bundled customers that would justify

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78 Phase 2 Decision at 43.

79 *Id.* at 43-44.

80 *Id.* at 44.

81 *Id*. at 13, citing PG&E's WG3 Proposal Opening Comments without reference to any particular page.

modifying PCIA calculations or requiring allocations of [RA] resources."[82] Apparently, however, rejecting actions to redress known imbalances, as was directed by the Phase 1 Decision, can be done without evidence at all.

# V. THE COMMISSION ABUSES ITS DISCRETION AND VIOLATES THE DUE PROCESS RIGHTS OF STAKEHOLDERS BY IGNORING DIRECTIVES IN D.18-10-019 AND REJECTING KEY ELEMENTS OF WG3'S PROPOSAL, ALLOWING THE PROCESS TO BE SUBVERTED

The Commission deferred central issues in this rulemaking from Phase 1 to Phase 2 in D.18-10-019, including "Portfolio Optimization and Cost Reduction" and "Allocation and Auction,"[83] and then specifically directed the use of a collaborative working group process, rather than a formal hearing process for those issues. Despite an intensive collaborative process and the submission of a strong proposal by the Co-Chairs, the Commission rejected several key elements of the WG3 Report. Instead, and contrary to the both the letter and spirit of the Phase 1 Decision, the Phase 2 Decision ignores the foundational "evidence" comprising the WG3 Report and allowed the working group process to be subverted. The Commission's treatment of the WG3 Report is an abuse of discretion contrary to Section 1757(a)(5) and violates the due process rights of all stakeholders in this proceeding in contravention of Section 1757(a)(6).

## A. The Commission Directed Work on Portfolio Optimization, Allocation and Auction Through a Collaborative Working Group Process

### 1. The Co-Chairs Conducted a Thorough and Robust Working Group Process as Directed By the Commission

In framing the R.17-06-026 working group process, the Commission described prior working group processes where "it was left to the directly interested stakeholders to work

[82] *Id*. at 42.
[83] Phase 1 Decision at 116, Ordering Paragraph 14 at 164.

together to develop and recommend functional solutions to the challenges before them…."[84] The Commission further stated:

> We anticipate that organizational workshops will facilitate refinement of the working groups scope, and that all participants shall assist with the preparation of a workplan for each working group, including a specific list of deliverables, and the schedule for completing the working group's self-assigned tasks by the end of October, 2019.[85]

The Commission then refined this proposal in its Scoping Ruling on February 1, 2019, placing "Portfolio Optimization and Cost Reduction" and "Allocation and Auction" in Working Group 3, and designating the Co-Chairs to lead the working group.[86] The Commission directed the parties to "work collaboratively" and "to report any difficulties immediately to the assigned ALJs."[87] The Commission left open the possibility for hearings within 10 working days after filing the Working Group Report.[88] Notwithstanding, the Commission emphasized that "the best opportunity for parties to materially influence the outcome of this working group process is to provide a consensus proposal in their final reports to the Commission."[89]

To comply with these directives the Co-Chairs created a process for analyzing and reviewing the statewide issues of portfolio optimization and allocation and action of PCIA-eligible resources in the IOUs' portfolios. As a result, the Co-Chairs' proposals for various resources in the IOUs' portfolios represented a consensus among them, based on a range of input from all interested parties in an intensive working group process. This intensive process included:

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84 *Id.* at 116.
85 *Id.* at 117.
86 Phase 2 Scoping Ruling at 9-10.
87 *Id.* at 12.
88 *Id.* at 8.
89 *Id.* at 14.

- ✓ Thousands of hours contributed by stakeholders and co-chairs.
- ✓ Co-led regular meetings (more than 60 meetings).
- ✓ Stakeholder Workshops (in person/phone) in 2019 on April 29, July 25, October 17, and December 11, with three in San Francisco and one in Southern California.
- ✓ Stakeholder Comments after each workshop, which were appended to the Final Report.
- ✓ Two Progress Reports in 2019, including comments thereon.
- ✓ One Final Report filed on February 21, 2020, with formal docketed comments.

SCE also maintained a Sharepoint site with a repository of materials (workshop materials, Co-Chairs work plan, meeting agendas, etc.) for parties to access.

The WG3 Report thus represents more than a year's worth of concentrated effort by the Co-Chairs and the stakeholders who participated actively throughout the development of the WG3 process.

The Commission, however, chose to change the rules after the game had been played. Ignoring the significant evidence and discussion surrounding these complex issues, and the resultant conclusions of the working group, the Commission abused its discretion by claiming the WG3 Report's proposals are "not supported by evidence."

Concomitantly, the Commission allowed certain parties to play a different game. Instead of participating collaboratively in the WG3 process, as the Scoping Ruling instructed, PG&E made proposals *well after* a solution was proposed by the Co-Chairs.[90] Nonetheless, the Commission appears to have given strong deference to PG&E's proposals, although these proposals disregard the significant compromises the Co-Chairs made in proposing a solution. In addition, as noted above the Commission also accepted without question or benefit of discussion

[90] PG&E's WG3 Proposal Opening Comments at 16, proposing "an alternative proposal [the "Attribute Distribution Framework"] for the Commission's consideration"); *Reply Comments of Pacific Gas and Electric Company (U 39 E) on the Power Charge Indifference Adjustment Phase 2, Working Group #3 Final Report*, Mar. 27, 2020.

the statements put forward by PG&E. The Commission thereby dispossesses the vast majority of stakeholders in this proceeding, including those represented by the Co-Chairs and those parties who actively participated and collaboratively developed the WG3 Report, of their due process rights.

### B. The WG3 Report is a Negotiated, Consensus and Unified Proposal, Intended to Balance Parties' Interests

Arrived at by representatives of major stakeholder groups after more than a year of deliberation, the WG3 Report and the proposals therein were intended to serve as a unified, integrated response to the myriad issues involved in the task the Commission ostensibly delegated to WG3. In fulfillment of the tasks assigned to them by the Commission, each of the Co-Chairs agreed to compromise positions on several important items in order to present a cohesive proposal to the Commission. Having reached and presented a collaborative compromise, the Co-Chairs presented collective and unified arguments to support their proposals, rather than devolving to individual litigation positions.

The Phase 2 Decision eviscerates this process. First, the Commission determines that each element of the proposal in the WG3 Report must be reviewed individually, and then it creates a new standard each proposal must meet. Finally, the Commission claims the proposals cannot be adopted because there is no litigation-style "evidence" to support each element, despite the abundant record created by WG3 itself.

#### 1. The Commission's Assessment of Each Element of the WG3 Report Individually and the Application of a New Standard to Each Element For Review Contravenes the Phase 1 Decision

Instead of assessing the WG3 Report, which represents compromise positions agreed to after intense and thoughtful deliberation, as a unified whole, the Commission reviewed each element of the WG3 Report in isolation. Further, the Phase 2 Decision created a new standard, determining that only resources determined to be "excess" under a newly applied definition could be subject to the efforts of WG3. As discussed in Section IV.A. above, the creation of this new standard contravened the express language and intent of the Phase 1 Decision.

### 2. The Commission Ignores the WG3 Report as "Evidence" of the Benefits of the Allocation and Market Offer Proposals

The Phase 2 Decision rejected two of the three key elements of the WG3 Report on grounds that it lacked evidence of the benefit of the RA and GHG-Free products. "Parties did not provide sufficient evidence in this proceeding to establish whether each IOU will have excess and/or uneconomic resources."[91] Further, the Commission stated it did not "have sufficient evidence of an observable and verifiable 'right of first refusal' benefit retained by bundled customers that would justify modifying PCIA calculations or requiring allocations of [RA] resources."[92] The Commission denied the WG3 proposal on GHG-Free resources and deferred further decision, and noted it "will consider as a next step in this phase of this proceeding whether GHG-Free resources are under-valued in the PCIA methodology, and whether to adopt a GHG-Free adder or an allocation mechanism."[93]

The Commission apparently expected litigation-style evidence to be produced to support what was a collaborative, negotiated, and collective approach. Of course, nothing in the record regarding the Phase 1 Decision, which plainly envisioned a consensus presentation, requires this type of "record." However, the Commission also apparently rejected the abundant record produced by WG3 and somehow fails to consider this within its definition of "evidence." But after significant discussion and analysis, the Co-Chairs recommended the WG3 proposals and put them forward on behalf of three critical industry segments. Their agreement alone that these

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91 Phase 2 Decision at 41.
92 *Id*. at 42.
93 *Id*. at 53.

were reasonable solutions constitutes more than sufficient "evidence" for the WG3 Report. The Commission abuses its discretion by rejecting the WG3 Proposal for RA and GHG-Free resources on the basis of an insufficient record.

In addition, the Commission's rejection of the WG3 Report itself, together with all of its supporting material as "evidence" sufficient for its decision, blatantly holds the WG3 participants to a different evidentiary standard than the Commission applies to PG&E. As noted previously, the Commission accepted without question many of PG&E's dramatic, and completely unverified, assertions regarding the potential impact of elements of the WG3 Report. Requiring the working group to produce more "evidence" is blatantly unfair to those parties who participated.

### C. The Commission Unfairly Allowed PG&E to Circumvent the WG3 Process

The Commission further ignored the failure of key stakeholders to participate in the WG3 process as directed. The Commission effectively deferred to the concerns of PG&E in rejecting the RA VAMO and GHG-Free Allocation yet ignored their failure to present alternative proposals during the workshop process and the development of the WG3 proposals. Without participating in the workshop process and actively engaging the stakeholder representatives at that time, PG&E denied the stakeholders the ability to discuss, value, and even counter the positions put forward.

The whole point of the WG3 process was to encourage and facilitate an exchange of views so that a negotiated, consensus position could drive Commission decision-making. Instead, the Commission accepts without question the conclusions put forward by PG&E, who did not engage collaboratively in the WG3 process, well after the development, and delivery, of the WG3 Report. As a result, the Phase 2 Decision effectively promotes the subversion of the

WG3 process, to the detriment of stakeholders who relied on the process created by the Phase 1 Decision.

Stakeholders, of course, did not know in advance that the Commission would require additional reams of testimony and discovery from each party in support of positions the Co-Chairs, as representatives of those stakeholders, were directed to develop. Stakeholders were of course also unaware the Commission would base its Phase 2 Decision not on fully vetted and analyzed proposals, but on untested statements from parties who chose not to participate in WG3. Instead, stakeholders relied on the Commission's direction in the Phase 1 Decision and on the Co-Chairs to implement those directions and craft a consensus set of proposals to address a statewide problem. The Commission's decision to change the rules of the game after the fact violates the due process rights of each stakeholder who participated in WG3.

## VI. RELIEF REQUESTED

For the reasons set forth above, the CCA Parties seek rehearing of the Decision to correct the legal errors identified in this Application.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

On Behalf of California Community Choice Association, Central Coast Community Energy, East Bay Community Energy, Peninsula Clean Energy, Silicon Valley Clean Energy Authority, and San José Clean Energy

June 23, 2021

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

| | | |
|---|---|---|
| Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program. | ) ) ) ) ) | Rulemaking 18-07-003 |

**DRAFT 2021 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLAN OF MARIN CLEAN ENERGY**

**PUBLIC VERSION**
**(Appendix E Redacted)**


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Dated: July 1, 2021

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

| | | |
|---|---|---|
| Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program. | ) ) ) ) ) | Rulemaking 18-07-003 |

**DRAFT 2021 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLAN OF MARIN CLEAN ENERGY**

**PUBLIC VERSION**
**(Appendix E Redacted)**

In accordance with the California Public Utilities Commission's ("Commission") March 30, 2021 *Assigned Commissioner and Assigned Administrative Law Judges' Ruling Identifying Issues and Schedule of Review for 2021 Renewables Portfolio Standard Procurement Plans* ("ACR"), Marin Clean Energy ("MCE" or "Agency"), hereby submits this 2021 Renewables Portfolio Standard Procurement Plan ("RPS Procurement Plan"). As directed by the ACR, this RPS Procurement Plan includes responses for the issues expressed in ACR sections 5.1-5.16.

MCE notes that certain issues and requests in these ACR sections apply to the other retail sellers (electrical corporations and electric service providers), and do not extend to Community Choice Aggregators ("CCAs"). MCE is nevertheless voluntarily responding to these ACR sections in the interest of transparency and in order to collaborate with the Commission. However, the submission of this RPS Procurement Plan pursuant to the ACR should not be construed as a waiver of the right to assert that components of Senate Bill ("SB") 790 (2012) or that Commission decisions and rulings on RPS Procurement Plan submittals do not extend to CCAs. MCE reserves the right to challenge any such assertion of jurisdiction over these matters.

In reviewing this RPS Procurement Plan, MCE encourages the Commission to consider the differences between California's investor-owned utilities ("IOUs") and other retail sellers, including CCAs. Differing levels of detail, procedure, complexity, and coordination within the planning documents submitted by these organizations are very appropriate.

**I. Major Changes to RPS Plan**

This Section describes the most significant changes between MCE's Final 2020 RPS Procurement Plan and its Draft 2021 RPS Procurement Plan. A redline of this Draft 2021 RPS Plan against MCE's Final 2020 RPS Plan is included as Appendix A. The table below provides a list of key differences between MCE's 2020 and 2021 RPS Procurement Plans.

**Table 1: Key Changes to MCE's RPS Procurement Plan**

| Plan Reference | Plan Section | Summary/Justification of Change |
|---|---|---|
| 2021 RPS Procurement Plan: Section III | Summary of Legislation Compliance | Updated to describe the process for taking official positions on legislation. |
| 2021 RPS Procurement Plan: Section IV | Portfolio Optimization | Updated to acknowledge the May 20, 2021, adoption of Decision ("D.") 21-05-030, which implements the Voluntary Allocation Market Offer proposal/framework, and potential RPS planning implications. |
| 2021 RPS Procurement Plan: Section IV.B | Responsiveness to Local and Regional Policies | Updated to describe impacts of local and regional policies on procurement targets, bid solicitation protocols, and forecasted supply. |
| 2021 RPS Procurement Plan: Section V | Project Development Status Update | Updated the project development status template, Appendix D, to reflect the recent progress of renewable generating projects that have yet to achieve commercial operation. |
| 2021 RPS Procurement Plan: Section VIII | Renewable Net Short Calculation | Updated the Renewable Net Short template, Appendix C, to reflect actual data from 2020 and updated projections through 2030. |

| | | |
|---|---|---|
| 2021 RPS Procurement Plan: Section XIII | Curtailment Frequency, Forecasting, Costs | Updated information regarding historical curtailments in Calendar Year 2021. |
| 2021 RPS Procurement Plan: Section XIV | Cost Quantification | Updated Cost Quantification template, Appendix E, to reflect updated cost projections associated with actual and planned RPS procurement. |

## II. Executive Summary

In this Draft 2021 RPS Procurement Plan, MCE provides information and updates regarding its progress in meeting applicable renewable energy planning and procurement targets, as well as additional detail in response to the expanded requirements set forth in the ACR.

MCE, California's first CCA, is a not-for-profit public agency that began service in 2010 with a mission to address climate change by reducing energy-related greenhouse gas ("GHG") emissions with renewable energy and energy efficiency at cost-competitive rates while offering economic and workforce benefits, and creating more equitable communities. MCE serves approximately 488,000 customer accounts in 34 communities across Contra Costa, Marin, Napa, and Solano counties, with annual retail sales of approximately 5,300 gigawatt hours. MCE offers its customers a minimum 60% renewable default service ("Light Green"), as well as two 100% renewable energy service options ("Deep Green" and "Local Sol").

MCE is governed by a board of 30 locally elected officials, which sets policy for the Agency and oversees its operations. Depending upon the issue, representatives from MCE's governing board generally convene two to three times per month with advance public notice provided in compliance with the Brown Act.

MCE continues to maintain an annual Integrated Resource Plan ("IRP") that focuses on planning and procuring resources needed to meet its demand as well as local and state environmental and reliability mandates. MCE's annual IRP is in addition to the biennial IRP mandated by SB 350 (2015). The IRP submitted to the Commission has been primarily oriented towards supporting California's achievement of its 2030 GHG reduction targets. MCE's annual IRP similarly addresses GHG reduction targets as well as various other matters related to resource planning and procurement, including complementary energy programs administered by MCE, over a forward-looking, 10-year period.[1] MCE's annual IRP is periodically updated and adopted by its Technical Committee (under delegated authority of MCE's governing board), memorializing the evolving policies and resource preferences of the Agency.

MCE's internal commitment to clean energy has resulted in a default supply portfolio that reached 60% renewable in 2017, thirteen years ahead of the statewide procurement mandate. MCE is also attentive to applicable long-term renewable energy contracting requirements and has secured 99% of its projected 2021 RPS requirements via numerous long-term contracts, exceeding pertinent long-term contracting requirement established by SB 350. MCE is also fully compliant with all Commission Resource Adequacy ("RA") requirements, to support the reliability needs of the state.

MCE maintains its clean, balanced portfolio by closely monitoring ongoing market conditions, including but not limited to curtailment, customer demand, and policy changes. MCE also monitors unanticipated market events, such as the COVID-19 pandemic, and their impacts on both the supply and demand sides of the market.[2] In optimizing its portfolio, MCE prioritizes the

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[1] Current versions of MCE's annual IRP, as well as the SB 350-required IRP, are available for review on MCE's website: https://www.mcecleanenergy.org/energy-procurement/.

[2] COVID-19 impacts are discussed more fully in Sections IV and VI, below.

maintenance of a balanced, diverse, and reliable portfolio; keeping its commitment to clean energy; and suppressing customer costs to the greatest practical extent.

MCE's commitment to clean energy has led the Agency to explore opportunities to mitigate the impacts of air pollution in regions of the state where communities have been disproportionately affected by the existing generating fleet, as well as the need to bring economic benefits to communities with high levels of poverty and unemployment. To address this concern, MCE continues to evaluate the procurement of "clean resource adequacy" ("Clean RA") and the feasibility (both technological and economic) of transitioning to increased use of carbon-free capacity sources to meet statewide reserve capacity mandates.

To reflect MCE's evolving resource preferences and impacts associated with recent changes to emission accounting practices reflected under California's Power Source Disclosure ("PSD") program, MCE intends to discontinue use of Portfolio Content Category ("PCC") 2 products in 2022 and beyond – more specifically, MCE's use of PCC2 products dropped to approximately 5.7% of retail sales in 2020 and is expected to drop again, to 3.4% of retail sales, in 2021 before moving to zero in 2022.

MCE's RPS Procurement Plan details its current solicitations and its bid review and selection processes. The Plan also describes how MCE applies the Least Cost Best Fit concept to its portfolio, to support its priorities as an agency created for the purpose of providing clean energy, among other things.

MCE continues to closely monitor its exposure to a variety of risk factors, as discussed more fully below in Section VII. MCE continues to find that its thorough analysis of both portfolio- and project- level risks, combined with its significant margin of over-procurement relative to statewide RPS goals, renders a quantitative risk assessment model unnecessary at this time. This noted, MCE continues to assess the need for such a model and may employ additional analytical tools in the future.

This RPS Procurement Plan also addresses new requirements specified in the March 30, 2021 ACR, including discussion related to MCE's process for taking official positions on legislation as well as commentary focused on the impacts of local and regional policies on MCE's procurement targets, bid solicitation protocols, and forecasted supply.

**III. Summary of Legislation Compliance**

This RPS Procurement Plan addresses the requirements of all relevant legislation and the Commission's regulatory framework. This Section describes the relevant statutory and regulatory requirements and how this RPS Procurement Plan demonstrates that MCE meets these requirements.

SB 350 was signed by the Governor on October 7, 2015. SB 350 set a new RPS procurement target of 50% by December 31, 2030. On December 20, 2016, the Commission issued D.16-12-040, which partially implemented the increased targets of SB 350 by establishing new compliance periods and procurement quantity requirements. On July 5, 2017, the Commission issued D.17-06-026, which implemented some of the key remaining elements of SB 350, including adopting new minimum procurement requirements for long-term contracts and owned resources, as well as revising the excess procurement rules. As discussed in greater detail in Section IV.B.1, MCE projects that 99% of its projected 2021 RPS procurement target will be met with long-term contracts.

SB 100 was signed by the Governor on September 10, 2018 and became effective on January 1, 2019. SB 100 increased the RPS procurement requirements to 44% by December 31, 2024, 52% by December 31, 2027, and 60% by December 31, 2030. On June 6, 2018, the

Commission issued D.18-05-026, which implemented changes made by SB 350 to the RPS waiver process and reaffirmed the existing RPS penalty scheme. In July of 2018, the Commission instituted Rulemaking ("R.") 18-07-003 to continue the implementation of the RPS. On June 28, 2019, the Commission issued D.19-06-023, which continues to use a straight-line method to calculate compliance period procurement quantity requirements. The current RPS procurement targets are incorporated in MCE's Renewable Net Short Calculation Table as further described in Section VIII below and attached hereto as Appendix C. On a projected basis, MCE's current RPS procurement is sufficient to exceed applicable targets through 2024, including a minimum margin of over-procurement based on MCE's risk assessment, as further described in Sections VII and IX.

Additional RPS procurement efforts remain ongoing, and MCE intends to augment existing RPS contracts with additional supply to promote statutory compliance, as well as the achievement of internal RPS targets, in 2025 and beyond.

SB 901, signed by Governor Brown on September 21, 2018, added Public Utilities Code Section 8388, which requires any investor-owned utility, publicly owned electric utility, or CCA with a biomass contract meeting certain requirements to seek to amend the contract to extend the expiration date to be five years later than the expiration date that was operative as of 2018. MCE does not have a contract with a biomass facility that is covered by Public Utilities Code Section 8388.

As a public agency, MCE takes official support positions on legislation subject to the authority delegated by MCE's governing board. MCE's governing board has granted it the authority to support legislation that 1) supports community choice aggregation in California, 2) reduces GHG emissions, 3) promotes local economic and workforce benefits, and 4) will benefit

CCA customers. These guidelines were approved by MCE's governing board in 2014.[3] Because of the rapidly-evolving nature of bills being considered by the California legislature in any given session, MCE cannot at this time identify any future legislative efforts that it may support.

Further, MCE is a member of the California Community Choice Association ("CalCCA"), which regularly takes formal support positions on legislation. A support position taken by CalCCA does not necessarily reflect the uniform support of every member of CalCCA, and thus should not be imputed to the individual members of CalCCA.

## IV. Assessment of RPS Portfolio Supplies and Demand

### IV.A. Portfolio Supply and Demand

Similar to its historical renewable procurement, MCE projects that it will meet or exceed applicable RPS procurement obligations over the long-term planning horizon (ten years and beyond), though the exact characteristics of MCE's supply portfolio may vary over time depending on market developments, policy changes, technological improvements, Agency preferences, and/or other factors. To manage this future uncertainty, MCE examines and estimates supply and customer demand, and will structure its future procurement efforts to balance customer demand with requisite resource commitments.

As previously noted, MCE's internally adopted renewable energy procurement targets have been set in excess of state-imposed mandates, creating a natural compliance buffer. For example, nearly 63% of MCE's aggregate supply portfolio was comprised of RPS-eligible renewable energy in 2020, an amount nearly double the statewide procurement mandate of 33%. Similar to previous years, this significant level of over-procurement would have accommodated

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[3] *See* Attachment to Agenda Item #10 from MCE's December 4, 2014 Board Meeting, available at https://www.mcecleanenergy.org/wp-content/uploads/2020/06/MCE-Board-Meeting-Packet-December_2014.pdf.

massive fluctuations in annual retail sales and/or anticipated renewable energy deliveries before triggering potential compliance risks for MCE. Given the significance of MCE's internally established minimum 60% renewable target, past success exceeding applicable compliance mandates, existing supply commitments, and ongoing planning/procurement efforts focused on RPS-eligible energy, MCE does not foresee any issues fulfilling future renewable supply commitments.

MCE continues to monitor the prospective impacts to its customer base associated with California's direct access market due to SB 237 (2018) and D.19-05-043, and is aware of a proposed decision in R.19-03-009 that rejects the further expansion of direct access at this time. MCE is monitoring, and engaged, in this proceeding and will continue to evaluate the potential impacts to its planning process. Should the proposed decision result in material changes to direct access availability for non-residential accounts, or direct access is expanded in the future, MCE will accordingly reflect such an outcome in its planning process. With this in mind, MCE's analysis shall remain ongoing and may result in future adjustments to MCE's load forecast and related renewable energy procurement obligations, which would be expected to decrease if MCE load migrates to direct access providers.

<u>Impacts of the COVID-19 Pandemic</u>

MCE is keenly aware of the current, worldwide COVID-19 pandemic, and its impact on "business as usual," including both demand and supply side impacts. Across retail sellers, commercial loads have decreased as a result of business closures or substantially modified operations, and residential loads have increased due to "stay at home" and "shelter in place" orders. MCE meets frequently to discuss observed variances between actual and anticipated customer energy use, including potential adjustments to upcoming load schedules. Based on available data and related analyses conducted to date, impacts to MCE's overall load and sales appear to be relatively modest, approximately 4%-5% lower than forecast.

As COVID-19 cases continue to decline and mobility restrictions have been relaxed as part of California's recent "reopening," MCE will continue to closely monitor the extent and pace at which retail electricity sales may return to historical norms. Much like load-related impacts throughout the pandemic, customer energy use during California's reopening and general economic recovery is difficult to predict – while nominal increases seem inevitable, such changes could be easily obscured by typical variations in weather. MCE continues to evaluate available data, attempting to parse various impacts on retail electricity consumption while incorporating adjustments to its planning assumptions on an as-needed basis.

MCE has also closely monitored supply-side impacts of COVID-19, including supplier and developer effectiveness in fulfilling renewable energy needs, project completion, and overall supplier viability. Like demand-related impacts associated with California's reopening, MCE intends to closely monitor developments that may affect supply, including general resource availability and project development status/viability. These potential impacts are further discussed in Section VI, below.

### IV.A.1. Portfolio Optimization

MCE plans for and secures commitments from a diverse portfolio of generating resources to reliably serve the electricity supply requirements of its customers over near-term, mid-term and long-term planning horizons. MCE's goal is to meet organizational policies and statewide mandates in a manner that is cost effective, achieves internally adopted clean energy objectives, promotes grid reliability, and generally supports a well-balanced and diversified resource portfolio. Portfolio optimization strategies can help reduce costs and should facilitate alignment of MCE's portfolio of resources with its forecasted needs. This noted, MCE has initiated a transition to the exclusive use of PCC1 renewable energy products by 2022 to minimize portfolio emission impacts that would otherwise accrue through the use of PCC2 and PCC3 product options, which are ascribed emissions under California's current emissions calculation methodology. This approach is significantly more costly to MCE's customers but will promote achievement of MCE's GHG-related objectives.

To support this goal, MCE considers the following strategies:

- Joint Solicitations: Joint solicitations can expand the procurement opportunities available to a CCA, as well as provide procedural efficiencies, economies of scale, and overall cost savings for participating organizations. MCE is closely networked with other CCAs through its membership in the CalCCA, the trade organization representing California's Community Choice Aggregation sector, and regularly coordinates with other CCAs regarding prospective procurement opportunities and portfolio balancing activities.
- Purchases from Retail Sellers: Purchases of RPS-eligible renewable energy (via resale) from other retail sellers can provide a cost-effective way of meeting short-term resource needs or filling in gaps in procurement while long-term projects are under development. MCE will evaluate solicitations offered by other retail sellers, as necessary.
- Sales Solicitations: As MCE continues to manage its growing portfolio of renewable resources, it will also consider administering sales solicitations (serving as a renewable energy seller) for the benefit of other retail sellers. Such solicitations are expected to be rare and relatively small in scale. MCE may also engage in bilateral sales discussions with certain retail sellers, including CCAs, if/when divesting relatively small amounts of surplus renewable energy supply is deemed necessary to rebalance MCE's renewable portfolio

relative to internally established procurement targets. MCE has completed such processes in the past and expects to do so in the future as well. Selling excess renewable supply is an effective way for all Load-Serving Entities ("LSEs") to reduce unnecessary renewable energy expenses while providing valuable renewable energy products to other market participants.

- Optimizing Existing Procurement: As MCE considers its long-term resource needs, it may evaluate options in its future power purchase agreements to increase the output of existing generating facilities through technological upgrades or by adding new capacity to an existing generator. Expanding existing facilities may provide additional generation at reduced costs with a lower risk of project failure because the need for distribution system upgrades and permitting may be minimized or eliminated.

On May 7, 2021, MCE received offers for its 2021 Open Season.[4] This process requested offers for the following products: 1) PCC1 renewable energy; 2) co-located or stand-alone energy storage; and 3) firm blocks of hourly PCC1 or carbon-free energy. MCE is currently in the process of evaluating these offers with the goal of having executed contract(s) by the end of the year. MCE's 2021 Open Season Request for Offers ("RFO") is summarized below:

1. 2021 Open Season RFO: The Open Season provides a competitive, objectively administered opportunity for qualified suppliers of various energy products (including renewable and storage technologies) to fulfill MCE's future resource requirements.
2. Disadvantaged Community Solar Green Tariff: MCE will be seeking qualified suppliers of new build solar projects to participate in MCE's 2021 Green Access

[4] *See* https://www.mcecleanenergy.org/energy-procurement/.

(Disadvantage Community – Green Tariff/ "DAC-GT") and Community Solar Connection ("DAC-CSGT") procurement process ("2021 Green Tariff"). The purpose of MCE's 2021 Green Tariff is to fulfill the requirements of Assembly Bill ("AB") 327, D.18-06-027, D.18-10-007, and Resolution E-4999 (collectively the "Green Tariff policy"). The Green Tariff policy is intended to promote the installation of renewable generation among residential customers in disadvantaged communities ("DACs").

a. In order to comply with the Green Tariff policy, MCE will procure under two programs: Green Access and Community Solar Connection. MCE will plan to hold one solicitation annually, beginning in 2021, until each program's capacity obligation is met.

3. Long-Duration Storage Request for Information: In June 2020, eight CCAs, including MCE, released a Joint Request for Information for long-duration storage resources.[5] The joint CCAs are in the project selection process to contract for up to 500 MW of capacity, energy ancillary products, and resource adequacy.

MCE's Open Season is typically administered on an annual basis for purposes of soliciting proposals for new-build renewable energy and storage resources that meet the procurement targets put forth in MCE's integrated resource plan. As part of the Open Season solicitation process, MCE provides an RFO Overview and Instructions document that details the volume of energy and resources eligible to bid, along with detailed information on required supporting documentation, evaluation criteria, schedule, and submittal process. In addition to the RFO Overview and Instructions, MCE supplies offerors with an offer form and term sheets for renewable project

[5] *See* https://www.svcleanenergy.org/joint-ld s-rfo/.

offers, renewables paired with storage and energy storage only offers.

MCE allows for 4-6 weeks for offerors to submit an offer, after which time MCE staff conducts a multi-phased approach for reviewing each offer. Offers are first reviewed for completeness relative to the RFO eligibility criteria. MCE then conducts a quantitative analysis focused on the value of each conforming offer and develops a short-list based on the project evaluation criteria. The short-list is then reviewed by MCE's Ad Hoc Contracts Committee and its Technical Committee. MCE enters into an Exclusivity Agreement for the strongest offers after this three-stage review, to ensure that favorable opportunities are not "lost" to other buyers.

Staff then begins contract negotiations with selected projects. The resulting Power Purchase Agreement(s) are reviewed by MCE's Executive Management team before review and approval by MCE's Technical Committee. Contract execution occurs after the PPAs are approved by MCE's Technical Committee.

Through the Power Charge Indifference Adjustment ("PCIA"), MCE customers (and other CCA and Direct Access customers) are required to pay their share of the above-market costs associated with Pacific Gas and Electric Company's ("PG&E") large hydroelectric fleet, PG&E's nuclear power plant, Diablo Canyon, and many PG&E Power Purchase Agreements ("PPAs") including RPS PPAs. Nearly half of PG&E's customer load has departed for other LSEs, resulting in PG&E having excess resources in its portfolio. PG&E offered to allocate a proportionate share of the 2020 output of the hydroelectric and nuclear, GHG-free, resources at no additional cost on a voluntary basis to CCAs and Direct Access providers whose customers pay the PCIA ("Interim Allocation"). Because MCE's governing board has elected not to take the nuclear allocations from PG&E to align with its policy of no resource-specific nuclear transactions, MCE has only accepted PG&E's hydroelectric allocations for 2020 and uses these allocations in meeting its internally adopted GHG-free targets. The Interim Allocation was extended into 2021 by Resolution E-5111, in which the Commission also authorized PG&E to extend the interim approach to GHG-Free resources through December 31, 2023.

Regarding the possibility of future allocations, the Final Report of Working Group 3 Co-Chairs: *Southern California Edison Company (U-338E) California Community Choice Association, and Commercial Energy* ("Final Report") was filed on February 21, 2020, in the Commission's PCIA rulemaking (R.17-06-026). One of the Final Report's key proposals was for the Commission to create a "Voluntary Allocation Market Offer" ("VAMO") framework, where each LSE serving customers subject to the PCIA would be provided an annual option to receive an allocation ("Voluntary Allocation") from the IOUs' PCIA-eligible RPS energy portfolios, based on that LSE's forecasted, vintaged, load share, and subject to certain conditions. Further, the Final Report proposed that any declined shares would be offered to LSEs through a market process ("Market Offer"). On May 20, 2021, the Commission adopted D.21-05-030, addressing the proposals in the Final Report. D.21-05-030 adopted the Final Report's VAMO proposal, subject to certain limitations and additional requirements.

To implement this modified VAMO structure, D.21-05-030 identifies various next steps, including a meet-and-confer process with the IOUs regarding the method for calculating potential Voluntary Allocations based on vintaged, annual load forecasts and a method for dividing the IOU's RPS portfolios into shares. This will be followed by the submission of an advice letter and workshops. As currently scheduled, IOUs and LSEs will confirm the LSEs' elections for Voluntary Allocation in February 2022, with contracting occurring in January or February of 2023. At this early stage, MCE is preliminarily reviewing its portfolio to determine whether and to what extent any Voluntary Allocation of RPS energy or participation in IOU Market Offers would benefit its position. MCE will provide an update on this topic in its next RPS Procurement Plan.

Finally, MCE is structuring its Light Green portfolio to be approximately 95% GHG-free in 2022 and beyond, subject to market and/or regulatory changes. To structure such a clean Light Green portfolio by 2022, MCE will procure three products: (1) RPS-eligible renewable energy; (2) large hydroelectric energy; and (3) Asset Controlling Supplier energy, the vast majority of which is attributable to large hydroelectric generating resources. To ensure grid reliability, MCE's contracting goals include 210 MW of stand-alone energy storage to be online by 2029, and to have approximately 320 MW of new energy storage paired with solar resources online by 2030. MCE notes, however, that it is also aware of the recent decision in R.20-05-003 that would require LSEs to procure 11,500 MW of capacity by 2026 and may affect these goals moving forward.[6] At this time, MCE's plans have not changed, but it will continue to evaluate, and provide an update in its next RPS Procurement Plan as necessary.

### IV.B. Responsiveness to Local and Regional Policies

(i) <u>Responsiveness to Policies of MCE Governing Board</u>

MCE is a local governmental agency that is subject to the control of its governing board and is directly accountable to the community that it serves. MCE strongly supports and is committed to meeting the state's GHG reduction and renewable procurement goals. As a member of CalCCA, MCE actively supported the passage of SB 100 (2018) and has fully incorporated the procurement requirements of the state's RPS program into its overall procurement strategy.

As previously noted, MCE's internally adopted renewable energy procurement target has been set at a minimum of 60%. All related renewable energy purchases will be sourced from

[6] *See* R.20-05-003, May 21, 2021, Proposed Decision of Administrative Law Judge Julie A. Fitch.

California Energy Commission-certified generating facilities, which will be eligible for use under California's RPS Program. The significant majority of MCE's renewable energy purchases will be sourced from products meeting the delivery requirements established for PCC1. Pre-2022, the relatively small balance of requisite renewable energy purchases will be sourced from products meeting the delivery specifications associated with PCC2. The prospective procurement of PCC3 products has been eliminated in MCE's annual IRP, and such purchases would only be pursued as a last resort, should market conditions preclude the cost-effective purchase of PCC1 or PCC2 products. In any case, MCE's procurement of PCC3 products will not exceed the limitations imposed under California's RPS Program.

Furthermore, MCE's existing contractual commitments have secured the significant majority of its renewable energy requirements. Existing contracts continue to address the majority of MCE's renewable energy needs throughout the planning period addressed in this RPS Procurement Plan, accounting for 68% of statutory renewable energy procurement requirements in 2030. MCE's planning and procurement process is ongoing, which is expected to result in additional renewable energy acquisition, the substantial majority of which will be secured via long-term contracts.

Additionally, MCE policy, established by MCE's founding documents and directed on an ongoing basis by MCE's governing board, guides development of the resource plan and related procurement activities. MCE's key resource planning policies are as follows:

- Reduce green-house gas emissions and other pollutants within the electric power sector through increased use of renewable, GHG-free, and low-GHG energy resources;
- Maintain affordable electric rates and increase control over energy costs through management of a diversified resource portfolio;

- Benefit the area's economy though investments in local infrastructure, energy, and workforce-development programs within MCE's service area;
- Help customers reduce energy consumption and electric bills by supporting and administering enhanced customer energy efficiency, cost effective distributed generation and, other demand-side programs;
- Pursue load and generation shaping to help reduce grid reliance on fossil power, manage costs, and promote reliability.
- Enhance system reliability through investments in supply- and demand-side resources;
- Actively monitor and manage operating risks to promote MCE's continued financial strength and stability; and
- Support supplier and workforce diversity as permitted by law.

MCE's Integrated Resource Plan translates these broad policy objectives into more specific plans for the use of various types of electric resources, taking into consideration MCE's projected customer needs and MCE's existing resource commitments.

To enable MCE to meet its resource planning objectives, MCE's governing board has formally adopted the following policies related to resource planning and procurement:

(1) MCE's Sustainable Workforce and Diversity Policy:[7] MCE is committed to supporting sustained and fairly compensated local job opportunities through participation in the energy industry. To the extent allowed by state law, MCE seeks to create market incentives and partnerships to encourage diversity and a sustainable workforce through its support for:

    - Fair compensation in direct hiring, renewable development projects, customer

[7] *See* Attachment A to Agenda Item #7 from MCE's November 16, 2017 Board Meeting, available at https://www.mcecleanenergy.org/wp-content/uploads/2020/05/MCE-Board-Meeting-Packet-November_2017.pdf.

programs, internships and procurement services;

- Development of locally generated renewable energy within the MCE service area;
- Direct use of union members from multiple trades;
- Quality training, apprenticeship, and pre-apprenticeship programs;
- Direct use of businesses local to the MCE service area;
- Development of California-based job opportunities;
- Business and workforce initiatives located in low-income and disadvantaged communities;
- Direct use of Disabled Veteran-owned Business Enterprises and LGBT-owned Business Enterprises;
- Direct use of green and sustainable businesses; and
- Use of direct hiring practices that promote diversity in the workplace.

(2) MCE's Energy Risk Management Policy:[8] MCE manages its energy resources and transactions for the purpose of providing its customers with low-cost renewable, carbon free and other energy, while at the same time minimizing risks. MCE procures energy and Resource Adequacy consistent with its Energy Risk Management Policy, which has been developed to ensure that MCE achieves its mission and adheres to policies established by the MCE Board of Directors, power supply and related contract commitments, good utility practice, and all applicable laws and regulations.

(ii) Responsiveness to Regional Policies

MCE is governed by a 30-member Board of Directors comprised of one elected

[8] *See* Attachment to Agenda Item #7 from MCE's May 2, 2019, Technical Committee Meeting, available at https://www.mcecleanenergy.org/wp-content/uploads/2020/01/MCE-Technical-Committee-Packet-May 2019.pdf.

Councilmember or Supervisor from each of our member communities and is committed to benefiting its service area's economy through investments in local infrastructure and energy programs. Though several of MCE's member communities have adopted their own climate, transportation, and/or land use goals or policies, MCE is not aware of any specific policies that require MCE to alter its resource planning or procurement practices at this time, nor is MCE aware of local or regional policies that would affect MCE's risk of RPS compliance at this time. In part, this may be due to MCE's voluntary renewable procurement targets that exceed state requirements and have been developed in conjunction with, and approved by, MCE's governing board.

However, MCE is committed to abiding by all local and regional plan criteria, as adopted by (or on behalf of) its member communities. When applicable, or in the instance that any new policies are enacted by MCE member communities that may affect MCE's resource planning process, MCE will work collaboratively with those communities to ensure continued compliance with the community, MCE, and the State policy goals.

**IV.B.1. Long-term Procurement**

MCE has been committed to supporting new, California-based renewable resource development since its inception, and has supported numerous generating assets via execution of long-term contracts. MCE has already executed long-term renewable contracts that are expected to yield approximately 99% of its total 2021 RPS renewable energy requirements (or 152% of MCE's expected RPS-related long-term renewable energy requirements). Further, most of the renewable energy supply solicited under MCE's Open Season is intended for projects with proposed delivery terms between ten and twenty years, which bolsters MCE's proportionate use of long-term renewable energy over time.

In light of its existing long-term supply commitments and anticipated future purchases, MCE expects to meet or exceed California's minimum 65% long-term contracting requirement, which became effective in 2021 and remains in effect through 2030. Even in the event of lower-than-anticipated deliveries from such contracts, MCE would still expect to satisfy the 65% long-term contracting requirement through 2029.[9] MCE expects to engage in additional long-term contract efforts to continue to meet or exceed the long-term contracting mandate.

### IV.C. Portfolio Diversity and Reliability

As part of MCE's forecasting and procurement processes, MCE also considers the deliverability characteristics of its resources including the expected delivery profile, available capacity and dispatchability attributes, if any, associated with each of its generating resource and/or supply agreements and reviews the respective risks associated with short- and long-term purchases. These efforts lead to a more diverse resource mix, address grid integration issues, and provide value to MCE's member communities, including reduced costs and support in achieving planned procurement objectives for the period addressed in this 2021 RPS Procurement Plan. A quantitative description of MCE's forecast is attached in Appendix C.

MCE is interested in emerging and viable technologies to meet the state's reliability needs. MCE's commitment to innovation and the advancement of renewable technologies continues to drive strategic opportunities for the inclusion of emerging technologies within its supply portfolio. For example, MCE has pursued supply commitments with renewable energy plus storage projects and is evaluating offers for emerging storage technologies as part of a joint CCA solicitation effort. The extent to which such technologies will be successful in mitigating

[9] This assumption is based on an unlikely shortfall in long-term contract deliveries approximating 12%, relative to MCE's total RPS projections in 2029. Prior to 2029, long-term renewable energy planning reserves are meaningfully greater than 12%.

conditions of over-supply, production variability and misalignments between energy production and customer use will be monitored over time to ensure that such contractual commitments are promoting desired outcomes.

MCE will continue to procure renewable and other GHG-free and conventional energy products, as necessary, to ensure that the future energy needs of its customers are met in a clean, reliable, and cost-effective manner. MCE has established proportionate procurement targets for overall GHG-free energy content, including subcategories for renewable energy and other carbon-free products, including related planning reserves.

In 2020, MCE also implemented an "equivalent carbon-free" portfolio metric, which considers the total emissions associated with each supply source relative to a target annual emission factor for its entire supply portfolio. For example, MCE's 90% carbon-free equivalent metric in 2020 allowed an overall portfolio emission factor equal to 10% of the California Air Resources Board's ("CARB") assigned emission factor for energy imports and system power, which is currently set at 0.428 metric tons of carbon dioxide equivalent per megawatt hour ("MT $CO_2e$"). Expressed differently, the 90% carbon-free equivalent metric limited, on a voluntary basis, emissions to an overall portfolio emission factor of 0.043 MT $CO_2e$. As reflected in its 2020 Power Source Disclosure report for Light Green service, MCE's actual 2020 emission factor of 0.035 MT $CO_2e$ was well below the organization's equivalent carbon-free emission target. The emission factor for both Deep Green and Local Sol service, as reflected in the respective 2020 Power Source Disclosure reports for each retail service offering, was zero.

Because certain renewable generating technologies are known to have relatively low levels of emissions, such as certain geothermal generating technologies, MCE's equivalent carbon-free metric captures such impacts, along with any other use of carbon-emitting supply, including system power and CARB-certified Asset Controlling Supply, to derive its proportionate use of carbon-free generation. To the extent that MCE's energy needs are not fulfilled through the use of renewable or other GHG-free generating resources, it should be assumed that such supply will be sourced from conventional energy sources, such as natural gas generating technologies or system power purchases.

MCE uses a portfolio risk management approach in its power purchasing program, seeking low-cost supply (based on then-current market conditions) as well as diversity among technologies, production profiles, project sizes and locations, counterparties, lengths of contract, and timing of market purchases. These factors are taken into consideration when MCE engages the market and pursues related procurement activities.

A key component of this process relates to the analysis and consideration of MCE's forward load obligations and existing supply commitments with the objectives of closely balancing supply and demand, cost/rate stability and overall budgetary impacts, while leaving some flexibility to take advantage of market opportunities and/or technological improvements that may arise over time. MCE monitors its open positions separately for each renewable generating technology as well as GHG-free resources, conventional resources, and its aggregate supply portfolio. MCE maintains portfolio coverage targets of up to 100% of expected customer energy requirements in the near-term (0 to 2 years), and typically leaves gradually larger open positions in the mid- to long-term, consistent with generally accepted industry practices.

MCE has a preference for zero emission generating technologies, but within this preference MCE is largely technology-agnostic.[10] MCE's supply preferences are intended to exhibit diversity across a broad range of renewable technologies that will deliver energy in a profile that is generally

[10] As mentioned above, MCE has a policy of not pursuing resource-specific nuclear power purchases.

consistent with MCE's anticipated load shape. MCE is aware that significant use of intermittent renewable generating technologies has the potential to create misalignments between customer energy consumption and related power production; however, MCE regularly evaluates customer usage in light of expected renewable deliveries to reduce such risks and inform future procurement decisions. Furthermore, MCE continues to consider procurement opportunities with renewable generating facilities that will utilize storage technology, which can materially re-shape the typical delivery profile associated with intermittent renewable generating assets, providing the opportunity for MCE to more closely balance supply and customer demand.

Recent market data continues to indicate that midday peak resources are likely to comprise a larger proportion of California's renewable supply portfolio due to the rapid decline in wholesale prices for solar PV generation and the abundance of such projects in operation and under development. Additions to MCE's portfolio during the Planning Period will likely be more heavily weighted toward energy resources – dispatchable, shaped during non-solar or ramping periods, or otherwise – that complement competitively priced solar already under contract or pair new solar projects with storage technologies to avoid exacerbating midday over-supply. MCE may also engage in purchases from as-available renewable generation (*e.g.*, wind) to the extent that such supply is competitively priced or otherwise provides electricity during time of day when existing supply commitments are currently lacking. Additionally, MCE is working with developers of its solar projects already under contract to add storage to those existing resources to increase the number of dispatchable resources in its portfolio.

In regard to project location, MCE places the greatest value on locally-sited renewable generating and storage projects, particularly those located in its service area or within approximately 100 miles thereof. In general terms, the next highest preference related to resource selection are projects sited within the North of Path 15 region (generally, Northern California), followed by projects elsewhere in California, and lastly, out-of-state resources. This procurement strategy has led MCE to achieve its desired clean energy portfolio objectives as well as cost-competitive customer rates. With this in mind, MCE intends to continue this approach in the future.

### IV.D. Lessons Learned

MCE's operating history has reinforced its belief that diversity among renewable energy commitments is highly desirable. This spans a broad range of considerations, including the use of various fuel sources, resource locations, contract durations, product specifications, pricing mechanisms, solicitation timing and frequency, as well as various other considerations. Early-stage discipline in renewable energy contracting allowed for MCE's solar energy commitments to gradually move down a declining cost curve, which avoided over-weighting the portfolio with an abundance of excessively costly contracts. As California's energy landscape continued to evolve, a concentration of renewable generating assets in certain locations reinforced the benefits of geographic diversity – as certain areas of the state were overbuilt with renewable generating infrastructure, challenges related to depressed market prices and related resource curtailments began to surface and will likely continue to exist for quite some time.[11] These observations have contributed to a more rigorous evaluation process for new generating projects, which is expected to reduce risks associated with such issues – while attempting to understand historical market pricing is not a perfect predictor of future performance, it seems to mitigate potential adverse

[11] It is noteworthy, however, that economic curtailment may not be feasible for certain retail sellers when considering the financial implications of long-term contract delivery shortfalls imposed under the RPS Program. In light of such significant financial charges, certain retail sellers may be forced to accept deliveries from renewable generating assets during instances of significant negative pricing to ensure that requisite long-term contracting quantities are satisfied. This could result in higher-than-anticipated renewable energy costs and related impacts to customer rates.

financial consequences during near-term operation of such facilities. In addition, MCE analyzes anticipated project development in a geographic area as well as planned network upgrades in the California Independent System Operator's ("CAISO") Transmission Planning Process.

Regarding long-term contracting, there is substantial financial risk associated with California's changing regulatory landscape. As California's energy market undergoes several significant changes over a short period of time, it seems impossible to predict how such long-term commitments will impact buyers and sellers, as well as affect costs for retail customers. While MCE works to protect the value of its contract when possible in the contracting process, it has seen the value of its resources degrade over time due to regulatory changes. If the regulatory rules under which the resources were originally contracted are not considered, MCE will inevitably lose value on the contracts it enters into, which discourages the long-term contracting the state has generally incentivized.

Another noteworthy lesson learned relates to the manner in which distinct California energy programs interact with one another. In particular, Assembly Bill ("AB") 1110 (stats. 2016) has devalued and, ostensibly, discouraged the use of certain renewable energy products (allowed for use under California's RPS Program) by virtue of the manner in which associated emissions are accounted for under the Power Source Disclosure Program ("PSD Program"). Specifically, changes to PSD Program regulations related to AB 1110 attribute an emissions factor equivalent to system power to any PCC2 and PCC3 volumes. In addition, PCC3 certificates are not presented as renewable purchases during power source accounting. This change has led MCE and various other CCAs to forgo or minimize the use of PCC2 and PCC3 products to avoid representing an inflated emissions factor and the potential public/customer perception that reported renewable energy content is lower than required under California's RPS Program or related policy commitments of the retail seller. This adaptation to MCE's planning and procurement practice became necessary despite the fact that such products are deemed eligible for use under California's RPS Program. MCE's transition to the exclusive use of PCC1 products (in 2022 and beyond) is expected to increase costs and customer rates.

**V. Project Development Status Update**

As described in Section IV.B above, MCE's current and planned procurement is sufficient to meet both the applicable RPS procurement requirements as well as support the state's GHG reduction targets. Further, MCE's current and planned procurement supports system reliability by considering both portfolio diversity and alignment with MCE customers' load curve.

As of the date of this RPS Procurement Plan, MCE has entered into nine utility-scale contracts with eligible renewable energy resources that are not yet commercially operational. Additionally, certain of MCE's Feed-In Tariff ("FIT") projects have successfully achieved commercial operation while others continue through the development process. These projects are supported via pricing schedules that are intended to promote developer interest while also offsetting higher-than-normal development costs typically associated with MCE's service territory. To date, MCE's FIT program has supported the completion of eighteen locally situated, small scale renewable generating projects, which are currently producing electricity that is purchased by MCE under long-term contracts. MCE has attached the Project Development Status Update Report as Appendix D.

**VI. Potential Compliance Delays**

MCE has received favorable determinations of compliance relating to Compliance Period 1 and Compliance Period 2, which indicate that "MCE met its RPS compliance obligations" during such periods. MCE expects similar determinations related to Compliance

Period 3, which includes calendar years 2017-2020, as well as future compliance periods. This perspective is based on MCE's past success in meeting RPS compliance mandates as well as MCE's internally adopted, above-RPS renewable energy targets and procurement activities, which show (on a projected basis) that the organization is tracking well ahead of schedule in satisfying applicable RPS mandates.

With regard to long-term contracting compliance, as discussed above, MCE has secured long-term contract commitments sufficient to meet the noted requirements through 2030, even in the event of potential delivery shortfalls.

**VI.1 Potential Impacts of COVID-19 Pandemic on Project Development**

As the Commission is aware, successful renewable energy markets depend upon international supply chains, substantial labor commitments, robust financial markets, timely interactions with governmental planning authorities and various other considerations. With numerous disruptions caused by the pandemic, it is challenging to determine whether, and to what extent, renewable energy procurement opportunities may be compromised, particularly new-build renewable energy projects that typically rely on long-term contracts as the basis for project financing. Throughout the pandemic, MCE has closely coordinated with suppliers that are developing new-build renewable generating assets and will continue to monitor this situation as well as potential fallout related to supplier/developer effectiveness in fulfilling expected renewable energy deliveries, project completion schedules and overall supplier viability. In light of diminishing concerns regarding COVID-19 infections and California's "reopening" in mid-June, MCE anticipates a gradual resolution of certain supply-side issues. This noted, MCE's above-RPS renewable energy procurement targets coupled with existing supply commitments from operational renewable generating facilities virtually eliminate any compliance-related concerns.

**VII. Risk Assessment**

MCE closely monitors development and operational risks associated with its planned and existing renewable energy supply commitments to minimize the potential for significant variances between actual and expected renewable energy deliveries.

Risk Oversight Committee and Energy Risk Management Policy

MCE has established a Risk Oversight Committee ("ROC"), which regularly convenes to discuss conformance of MCE's ongoing planning and procurement efforts with the organization's adopted Energy Risk Management Policy ("ERM Policy"). MCE's ERM Policy was developed for the purpose of creating and maintaining controls and processes that will mitigate potential exposure to various sources of risk, including market price risk, counterparty credit and performance risk, load, and generation (volumetric) risk, operational risk, liquidity risk and policy (*e.g.*, legislative and regulatory) risk.

To the extent that higher-than-expected renewable energy open positions, counterparty over-exposure, meaningful load variations or other pertinent planning observations are identified during meetings of the ROC, MCE adjusts procurement activities to address these concerns, which promotes ongoing compliance with its ERM Policy. Should any significant ERM Policy deviations be identified, MCE staff would inform its Governing Board before pursuing corrective action. MCE's risk assessment and management practices are described in greater detail below.

Risk Assessment and Management Processes

In general terms, MCE's process for minimizing and avoiding risk is deterministic in nature and begins with the development of bid requirements and evaluative preferences for solicitations. MCE's solicitations are intended to identify suppliers that have demonstrated a strong track record of successful project completion and ongoing project operation. Such counterparties are more likely to timely complete project development activities and successfully operate projects placed under contract, and therefore minimize project risks. This process has yielded strong results: the pool of responses to MCE-administered solicitations is generally robust; the quality of short-listed respondents is high and typically includes very experienced bidders with strong project development track records; the short-listed candidates, by virtue of their considerable project development and/or operational experience, tend to be efficient contract negotiators; and the resulting contracts have generally led to project deliveries that meet MCE's expectations.

Key risk factors are considered during evaluation of each prospective renewable energy seller, including counterparty credit rating and general financial standing; California-based project development experience; prior experience with CCA off-takers; commercial viability of the proposed generating technology; and progress towards key development milestones such as interconnection status, deliverability studies, siting, zoning, permitting, and financing requirements. With regard to transmission adequacy, MCE ensures that each project has an executed interconnection agreement with the appropriate participating transmission operator prior to contract execution so that the project's interconnection costs, deliverability and timelines are known to the extent possible. MCE also conducts a review of interconnection queues and transmission planning in the area to understand impacts of planned projects and transmission upgrades. The project review process also includes a thorough review of the permitting status from the permitting authority and must demonstrate a path to completion. A selected seller bears risk of supply chain delays impacting the seller's ability to meet its guaranteed contractual milestones on time, subject to permitted extensions and allowable Force Majeure provisions in the contract.

To the extent that a prospective renewable energy procurement opportunity comes to fruition, and a contract is executed, development milestones are rigorously monitored by MCE's contract management staff, who regularly communicate with the project sponsor throughout the development and construction processes.

MCE also seeks to minimize unnecessary financial exposure and general planning risk by assembling a diversified portfolio of renewable generating resources and products that are intended to complement the manner in which its customers use electric power. To promote this alignment of supply and demand, MCE analyzes the impacts of proposed renewable energy deliveries to its aggregate resource portfolio relative to expected customer energy use as part of its evaluation process. To the extent that the proposed delivery profile would create undesirable net-short or net-long positions, alternative product options will continue to be evaluated. MCE may also pursue contract structures that promote volumetric stability through firm delivery quantities and/or performance guarantees that provide for financial remedies/penalties in the event of delivery shortfalls. If necessary, the financial remedies received by MCE could be used to: (1) as a first priority, procure additional renewable energy supply to address delivery shortfalls; or (2) in the event that the delivery shortfall caused MCE to be found non-compliant, offset the cost of related penalties. MCE's intent is to exceed compliance with applicable RPS mandates, and the latter option is a last resort that is not expected to apply.

Additionally, MCE believes that it is important to manage temporal risks associated with: (1) disproportionate exposure to prevailing market conditions at any particular point in time; and (2) lack of diversity related to contract start dates, end dates or term lengths within a renewable energy supply portfolio. MCE has regularly administered renewable energy solicitations throughout its operating history to ensure that its exposure to ever-changing market conditions is diversified, similar to the "dollar cost averaging" methodology that is regularly employed within the financial sector.

While attempts to "time the market" may occasionally yield short-lived benefits, such results are generally not reliable and create the potential for significant risk and financial consequences if market conditions quickly and/or significantly change. MCE's deliberate contracting approach entails "sampling" the market at regular intervals, avoiding large contractual commitments in high-priced environments or missed opportunities in low-priced environments. MCE also ensures that its contract start/end dates and related term lengths are staggered to avoid planning "cliffs" that could occur if contracts of similar lengths and start dates were all executed at the same time. The assembly of short-, medium- and long-term contracts further diversifies risk within MCE's renewable supply portfolio, and while increased long-term RPS contracting requirements will inevitably increase such risks, MCE will continue to pursue portfolio diversity by thoughtfully considering these temporal considerations during ongoing procurement processes.

Ongoing Evaluation of Need for Quantitative Risk Assessment Model

MCE continues to evaluate the need for a quantitative risk assessment model. MCE's rigorous process for evaluating prospective suppliers continues to be successful in identifying highly qualified, financially viable candidates and supporting its achievement of both statutory and voluntary renewable energy procurement goals.

Because MCE's minimum renewable content commitment substantially exceeds the current statewide goal, MCE continues to find that use of a quantitative risk assessment model is not critically important in meeting pertinent RPS compliance mandates. MCE will continue to evaluate the usefulness of such tools as it moves forward. Should MCE identify compliance-related concerns through application of its ERM Policy or other mechanisms, MCE will take the appropriate course of action, which may include quantitative risk assessments or other planning studies, to address such issues before compliance is affected.

MCE's Compliance Risk is Minimal

In terms of its ability to demonstrate compliance with California's RPS procurement mandates, MCE does not anticipate any particular development or operational risks that would materially impact its planned progress in this regard. This perspective is supported by the aforementioned supplier selection process as well as MCE's internally adopted renewable energy procurement target. However, the possibility always exists that future renewable energy supply will not be delivered as required under each respective power purchase contract. MCE considers this potential risk in forecasting as well as during procurement review and decision-making.

System Reliability

With respect to system reliability, MCE is aware of the planning challenges faced by retail sellers with internally adopted renewable energy targets that exceed RPS mandates. In particular, such retail sellers must often bear increased costs for renewable resources with diverse and complementary delivery profiles, as well as comparatively high levels of energy storage infrastructure to allow for the reshaping of renewable energy deliveries to better align with load.

For example, renewable energy procurement efforts that may initially focus on relatively low-cost solar resources will often necessitate subsequent investments in co-located energy storage infrastructure and/or higher-cost baseload renewable generating technologies, such as those using geothermal, biomass and landfill gas fuel sources. These baseload renewable technologies are often priced at three-to-four times the level of in-state photovoltaic solar generation but generally provide increased capacity value due to the more predictable, baseload generating profiles of such resources, and related reliability enhancements.

In spite of the adverse budgetary impacts, MCE continues to pursue resource acquisitions that will promote increased alignment between supply and demand as well as the increased use of locally situated renewable generating resources. Currently, low-cost, long-term solutions are incredibly challenging to identify, as ongoing increases in California's RPS procurement mandates and technological limitations often create the need for near-term investments to balance the achievement of compliance mandates with generalized grid reliability.

Nonetheless, MCE remains committed to pursuing a conscientious planning process that balances grid reliability, compliance demonstration and customer cost impacts. Again, there are no easy solutions in addressing this dilemma, but MCE's commitment to pursuing alignment of supply and demand as well as general resource diversity should contribute to grid reliability, reducing related risks for MCE's customers and the system at large.

Lessons Learned

In terms of lessons learned related to risk management, MCE has observed that "more is generally better" when it comes to procuring renewable energy to satisfy RPS compliance obligations. And while this approach may not be a viable or desirable option for all retail sellers, it has served MCE well. More specifically, MCE's minimum 60% renewable energy commitment (which gradually increases to 85% in 2029) has positioned the organization with substantial RPS planning reserves and minimal compliance risk. Since the minimum 60% renewable energy commitment became effective in 2017, the risks faced by MCE have transitioned away from compliance-related concerns to the areas of integrated resource planning. MCE is now focused on identifying resources that are not only cost-effective, but complementary to its existing portfolio of renewable energy supply contracts and projected customer energy use. As the level of renewable energy increases within MCE's portfolio, MCE has observed that the scope of resources promoting alignment between supply and demand generally becomes narrower and more costly.

There is also concern related to the management of long-term renewable supply commitments that exist within geographic areas where negative price risk and related curtailment of energy production has become increasingly prominent. This risk is becoming more challenging to manage as California's escalating RPS procurement mandates necessitate ongoing investment in new renewable generating infrastructure, which is often sited in resource-rich areas that become oversaturated with similar generating technologies. These circumstances seem inevitable and, over the course of a long-term supply relationship, may expose the contracted parties to unexpected risks, including negative prices (and related budgetary impacts) and curtailed deliveries which may compromise the fulfillment of mandated procurement targets by the buyer. However, MCE's internally adopted, above-RPS renewable procurement targets allow flexibility if/when curtailment becomes necessary, or when contracted renewable resources underperform.

In terms of MCE's contracting process, MCE has also learned that diversified sharing of risk within a renewable contract portfolio is desirable. There are many different contract structures, all of which serve a valuable purpose, that can be employed to create the desired allocation of risk between buyers and sellers. For example, an "index-plus" pricing structure is useful in transferring nodal price risk to the seller. In such structures, the buyer pays a fixed renewable premium, while the seller assumes risk associated with market price fluctuations but also receives market revenues – even though the buyer receives the energy, renewable attribute and, in certain instances, capacity value as part of such a transaction, the buyer's financial risk is generally limited to the payment of the renewable premium. For buyers who are averse to market price risk, the index-plus pricing structure effectively eliminates this concern but may result in a higher overall contract costs, which may be acceptable as a form of insurance, to mitigate market price exposure.

In other structures, such as the "fixed-price" or "aggregate pricing" structure, the renewable energy premium and energy commodity (and oftentimes, capacity value) are reflected in a single price paid by the buyer – this structure deliberately allocates market price risk to the buyer, but the buyer may also pay a lower imputed renewable premium in instances where market revenues closely approximate, or exceed, the aggregate renewable energy price.

In considering potential contract structures, decisions are ultimately made in consideration of risk allocation preferences, and MCE has found that it is generally desirable to pursue broad diversity in renewable energy contracting, inclusive of resource location, generating technology, suppliers/developers, and contract structures, amongst other considerations. MCE acknowledges, however, that newer retail sellers that have yet to establish meaningful financial reserves or cost-conscious retail sellers, who may be working to suppress power supply costs in consideration of a cost-sensitive customer base, may choose to favor arrangements that allocate market price risk to sellers/suppliers, particularly during early-stage operations.

Finally, MCE has learned that every CCA is different and that there is no pre-determined risk management methodology or procurement approach that is without challenges. Pursuing resource diversity across a broad spectrum of planning considerations over the long-term planning horizon appears to be one of the most viable mechanisms in mitigating RPS compliance risk.

## VIII. Renewable Net Short Calculation

MCE's failure rate for new-build renewable generation placed under contract is well below five percent. MCE takes several steps to guard against the risk of project failure, including:

- Pre-contracting diligence, including a rigorous proposal evaluation process. MCE requires that any new-build project be in an advanced stage of the pre-development process, including permitting, financing, and interconnection. In particular, MCE's practice is to execute a PPA only after a project's interconnection agreement is fully executed. This increases certainty with regard to the project's development timeline and costs.

- Project monitoring, MCE's PPAs for new-build projects require frequent, detailed progress reports, which helps to identify and mitigate potential problems in their early stages.
- Internal renewable portfolio targets, including a planning reserve, that meaningfully exceed statewide mandates.

MCE has increased its planned procurement to account for an approximate three percent failure rate in 2021, increasing to four percent in 2029, for both online generation and facilities in development. These percentages are reflected in Appendix C. These adjustments were made to reflect 1) limited delivery reductions from geothermal facilities impacted by nearby wildfires, and 2) occasional curtailment of select in-state solar facilities due to negative pricing at certain times of the year. Both of these shortfalls, even taken together, create impacts well below the 3%-4% risk adjustment described here. MCE continues to use actual planning data as compared to its forecast throughout the year, and can adjust to supply- or demand-side variations within a given year.

MCE has provided a quantitative assessment to support the qualitative descriptions provided in this RPS Procurement Plan, which is attached as Appendix C. At this point in time and based on MCE's past success, current supplier performance and anticipated renewable energy contracting outcomes, there have been no risk-related adjustments to the expected renewable energy quantities reflected in Appendix C. As previously noted, MCE has successfully procured more than 60% of its resource needs from RPS-eligible renewable resources since 2017 and, as a result, has accrued renewable energy well in excess of applicable statewide mandates. In general terms, renewable suppliers have performed as expected, and as such MCE did not find it appropriate to incorporate risk adjustments at this point in time. If supplier performance becomes more erratic in the future and such adjustments are deemed necessary, MCE will reflect such adjustments in a future planning document.

## IX. Minimum Margin of Procurement (MMoP)

The following table displays MCE's intended margin of RPS over-procurement based on the differential between the SB 100 procurement targets and MCE's internally adopted RPS procurement targets.

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **SB 100 RPS Procurement Requirement (% of Retail Sales)** | 35.8% | 38.5% | 41.3% | 44.0% | 46.7% | 49.3% | 52.0% | 54.7% | 57.3% | 60.0% |
| **MCE RPS Procurement Target (% of Retail Sales)** | 61.8% | 61.9% | 62.2% | 62.2% | 67.0% | 71.7% | 76.5% | 81.2% | 86.0% | 86.0% |
| **MCE Minimum Margin of Over-Procurement (% of Retail Sales)** | 26.0% | 23.4% | 20.9% | 18.2% | 20.3% | 22.4% | 24.5% | 26.6% | 28.6% | 26.0% |

MCE's RPS-eligible renewable energy target is currently set at a minimum 60 percent through 2024, increasing to 85 percent by 2030. Percentages reflected in the above table include these minimum percentages, plus additional renewable energy volumes required to serve anticipated participation in MCE's voluntary 100% renewable service options – such percentages are reflected in the line item labeled "MCE RPS Procurement Target (% of Retail Sales)". Consequently, MCE's RPS supply portfolio is expected to reflect a minimum margin of over-procurement that will minimally exceed statewide RPS mandates by at least 18 percent (relative to retail sales) in each year of the 10-year planning horizon.

### IX.A. MMoP Methodology and Inputs

MCE's internally adopted renewable energy planning targets reflect minimum procurement of 60% RPS-eligible renewable energy through 2024, increasing to a minimum 85% by 2029. As illustrated in the table above, this provides MCE with a minimum margin of over-procurement well in excess of the risks accounted for in the planning margin described in Section VIII, including but not limited to, potential project development failure, deficient production by facilities under contract, unusually high demand, and availability of requisite renewable energy products within the marketplace.

### IX.B. MMoP Scenarios

MCE plans to meet the annual program renewable goals reflected in the table presented in Section IX (above), including the MMoPs reflected therein. As reflected in this table, MCE's anticipated MMoP percentages range from 18.2% in 2024 to 28.6% in 2029. MCE's RPS Procurement Targets, as well as the renewable net short reflected in the RNS Quantitative Template, incorporate the additional RPS-eligible renewable energy need resulting from expected participation in MCE's voluntary 100 percent renewable energy service options.

During its bid evaluation and supplier selection processes, MCE considers a variety of risks and believes that such risks are sufficiently addressed within its MMoP calculation. Based on its operating history, previous experiences related to renewable energy planning/procurement and existing contract portfolio, MCE has no reason to doubt the sufficiency of the MMoP reflected in its internally adopted RPS planning targets. This noted, MCE has incorporated an internal RPS planning reserve, as reflected in the following table, to ensure MCE can meet its internal RPS targets in the event that its previously described contract management process identifies substantial concerns related to new-build project completion, delivery shortfalls or other issues.

This reserve is additive to MCE's internally adopted RPS targets and is intended to address renewable production and/or usage variability that may occur during discrete calendar years. It is intended to offset the potential impacts of noted risk adjustments/contingencies that may reduce actual renewable energy deliveries, relative to MCE's expectations. In effect, MCE's internal RPS planning reserve is a secondary MMoP, providing additional insurance against unforeseen circumstances that could impact MCE's ability to satisfy its internally adopted renewable energy commitments. As demand- and supply-side data are monitored in each year, MCE may adjust planned short-term purchases and/or pursue surplus sales arrangements if actual renewable energy deliveries are tracking above MCE's anticipated needs. By the end of each calendar year, MCE hopes to manage the level of its internal planning reserve so that actual renewable energy deliveries are closely aligned with MCE's Base RPS Procurement Target, as reflected below.

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **SB 100 RPS Procurement Requirement (% of Retail Sales)** | 35.8% | 38.5% | 41.3% | 44.0% | 46.7% | 49.3% | 52.0% | 54.7% | 57.3% | 60.0% |
| **MCE Base RPS Procurement Target (% of Retail Sales)** | 61.8% | 61.9% | 62.2% | 62.2% | 67.0% | 71.7% | 76.5% | 81.2% | 86.0% | 86.0% |
| **MCE Minimum Margin of Over-Procurement (% of Retail Sales)** | 26.0% | 23.4% | 20.9% | 18.2% | 20.3% | 22.4% | 24.5% | 26.6% | 28.6% | 26.0% |
| **MCE Internal RPS Planning Reserve (% of Retail Sales)*** | 5.7% | 5.7% | 5.7% | 5.7% | 6.1% | 6.6% | 7.1% | 7.5% | 8.0% | 8.0% |
| **MCE Total RPS Procurement Target (% of Retail Sales)** | 67.5% | 67.6% | 67.8% | 67.9% | 73.1% | 78.3% | 83.5% | 88.7% | 93.9% | 93.9% |
| **MCE Total Margin of Over-Procurement (% of Retail Sales)** | 31.7% | 29.1% | 26.6% | 23.9% | 26.4% | 29.0% | 31.5% | 34.1% | 36.6% | 33.9% |

***Includes volumes that may be necessary to address potential RPS delivery shortfalls; may be adjusted during each calendar year, as needed.**

MCE will also model demand-side sensitivities that may impact MMoP calculations. This will be particularly important during expansion of MCE's service area, when participation rates are expected to be most volatile. MCE has completed numerous expansions during its 11-year operating history, and in each case, MCE has successfully scaled its renewable energy procurement to accommodate related increases in retail sales. In addition to load variability resulting from periodic expansions and ongoing minor fluctuations in customer participation, MCE will also monitor electric vehicle penetration rates, net energy metering participation rates and other considerations that may impact overall customer energy requirements and related MMoP calculations.

## X. Bid Solicitation Protocol

### X.A. Solicitation Protocols for Renewables Sales

MCE does not have immediate plans to issue a solicitation for sales of renewable energy projects.

### X.B. Bid Selection Protocols

In its various solicitations for long-term renewable energy supply, MCE imposes numerous bid requirements on interested respondents. These requirements address a variety of considerations and are intended to identify the best qualified suppliers of MCE's long-term renewable energy needs. Such requirements include:

1. Overall quality of response, inclusive of completeness, timeliness, and conformity;
2. Price and relative value within MCE's supply portfolio;
3. Project location and local benefits, including local hiring and prevailing wage considerations;
4. Project development status, including but not limited to progress toward interconnection, deliverability, siting, zoning, permitting, and financing requirements;
5. Qualifications, experience, financial stability, and structure of the prospective project team (including its ownership);
6. Environmental impacts and related mitigation requirements, including impacts to air pollution within communities that have been disproportionately impacted by the existing generating fleet;
7. Potential impacts to grid reliability;
8. Potential economic benefits created within communities with high levels of poverty and unemployment;
9. Acceptance of MCE's standard contract terms; and
10. Development milestone schedule, if applicable.

These considerations help shape the criteria against which prospective suppliers are evaluated. Based on the success of its ongoing planning and procurement efforts as well as any direction from its governing board, MCE may adapt these considerations in future renewable energy procurement efforts.

Consistent with Public Utilities Code Section 399.13(a)(6)(C), MCE conducts energy product solicitations in a manner that addresses a broad range of considerations, including specific needs for eligible renewable energy resources (reflecting locational preferences, when applicable, for such resources), generating capacity, and required online dates to assist in determining what resources fit best within its desired supply portfolio. Since MCE's governing board is comprised of local elected officials, solicitation and procurement decisions are overseen by elected representatives of MCE's member communities with such decisions intended to conform with locally established targets that exceed applicable RPS requirements and promote the development of locally-situated renewable generating facilities.

MCE's 2021 solicitations are cited in Section IV.A and materials, including applicable contract templates and general information regarding MCE's solicitation processes are available at the following website: https://www.mcecleanenergy.org/energy-procurement/.[12] Information regarding other MCE service offerings and programs, including its FIT, can be found elsewhere on the MCE website.

### X.C. LCBF Criteria

The Least-Cost Best Fit ("LCBF") methodologies approved by the Commission pursuant to D.04-07-029, D.11-04-030, D.12-11-016, D.14-11-042, and D.16-12-044 are expressly only directly applicable to investor-owned utilities. However, consistent with Section 399.13(a)(9),[13] MCE does consider best-fit attributes that support a balanced mix of resources to help support grid

[12] Note, that MCE's Green Tariff/Green Access solicitations are currently in the process of being added, and that the Joint CCA Long Duration Storage RFO information is hosted on Silicon Valley Clean Energy's website at https://www.svcleanenergy.org/joint-lds-rfo/.

[13] Cal. Pub. Util. Code § 399.13(a)(9) ("In soliciting and procuring eligible renewable energy resources, each retail seller shall consider the best-fit attributes of resource types that ensure a balanced resource mix to maintain the reliability of the electrical grid.").

reliability.

With regard to MCE's application of an LCBF methodology during selection of qualified responses, the term "costs" should appropriately include considerations beyond the basic price of renewable energy being considered for procurement. Specifically, costs should include considerations such as: (1) reputational damage resulting from failure to meet internally established renewable energy procurement targets; (2) compliance penalties resulting from failed project development efforts or delivery shortfalls; (3) administrative complexities related to dealing with inexperienced suppliers (such as prolonged contract negotiation processes and uncertainties related to project milestone timing and achievement); and (4) impacts to planning certainty resulting from higher-risk projects. MCE considers these factors, among others, as part of its cost evaluation process, which may lead to the selection of offers that aren't necessarily the lowest-priced option.

"Fit" also has as much to do with organizational compatibility between buyers and sellers and alignment with key organizational objectives as it does with balancing customer usage and expected project deliveries, particularly when considering long-term contracting opportunities that will require constructive working relationships over a period of ten years or more. As such, MCE's LCBF methodology takes into consideration the various planning and procurement processes described in this RPS Procurement Plan, balancing a variety of pertinent considerations at the time that each renewable purchase opportunity is being considered.

An important example supporting this perspective is MCE's FIT program, which is intended to incentivize, through above-market prices, the development of locally situated, small-scale renewable project developments. This program has achieved tremendous success, supporting numerous projects throughout MCE's service territory while utilizing local labor. By design, FIT projects are not the least expensive generating resources, but they are entirely consistent with MCE's charter objectives and a valuable component of MCE's supply portfolio.

This holistic planning approach, which may not necessarily reflect a traditional LCBF methodology, has resulted in the compilation of a diverse resource mix for MCE, deep roots in its member communities, and attention to a broad spectrum of considerations, including environmental concerns, costs and sustainability.

Finally, the requirement of Section 399.13(a)(8) to give preference to renewable projects located in certain communities is expressly only applicable to "electrical corporations" and is not mandatory for CCAs.[14] However, MCE fully recognizes the need to help mitigate the impacts of air pollution in regions of the state where communities have been disproportionately impacted by the existing generating fleet as well as the need to bring economic benefits to communities with high levels of poverty and unemployment. As noted previously, MCE submitted Advice Letters to participate in the Commission's Disadvantaged Community Solar Green Tariff program with the intent to hold a solicitation in the third quarter of 2021 for qualifying resources. MCE continues to explore opportunities to advance this important policy goal through its procurement.

## XI. Safety Considerations

MCE holds safety as a top priority. Since MCE does not own, operate, or control generation facilities, MCE's procurement of renewable resources does not present any unique safety risks. MCE's Power Purchase Agreement include safety terms such as Prudent Operating Practice and Maintenance of Health and Safety provisions, which speak to safety precautions with respect to

[14] Cal. Pub. Util. Code § 399.13(a)(8)(1) ("In soliciting and procuring eligible renewable energy resources for California-based projects, each electrical corporation shall give preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases.").

the operation, maintenance, repair and replacement of a project.

This Section describes how MCE has taken actions to reduce the safety risks posed by its renewable resource portfolio and how MCE supports the state's environmental, safety, and energy policy goals.

### XI.1. Wildfire Risks and Vegetation Management

At this point in time, MCE has yet to adopt any additional safety requirements for its portfolio that are specific to wildfire risks and vegetation management. MCE is aware of the mitigating impacts that biomass generators, which use forestry waste as feedstock, may have on wildfire risk, but does not have any specific procurement policies or preferences for forest biomass resources at this time.

### XI.2. Decommissioning Facilities

MCE does not own any generating assets, and as such does not undertake decommissioning of assets. MCE has not yet developed any plans or requirements related to the disposition of associated generating facilities following completion of applicable delivery terms. In many cases, the project's operational life is longer than MCE's contract, so it is likely that the contract with MCE will expire before disposal of the generation assets is required.

In 2015, SB 489 authorized the California Department of Toxic Substances Control ("DTSC") to add photovoltaic ("PV") panels to the list of universal wastes. The DTSC has developed regulations for PV panels, but has not adopted the regulations yet.[15] Because a significant portion of MCE's solar facilities are newly constructed, and its storage facilities are yet to be constructed, MCE is confident that by the time PV solar or battery facilities under contract with MCE reach the end of their useful life, there will be statewide, comprehensive regulations

[15] See https://dtsc.ca.gov/photovoltaic-modules-pv-modules-universal-waste-management-regulations/.

addressing the safe handling and disposal/recycling of those materials.

### XI.3. Climate Change Adaptation

MCE's commitment to increasing renewable energy at a more aggressive pace than California's statewide mandates itself constitutes a climate change adaptation measure. Additionally, MCE in 2019 adopted a pollinator-friendly habitat requirement for solar projects participating in both its FIT program as well as its PPAs.[16] MCE is the first California CCA to adopt this requirement, which is a critical way MCE can help build and maintain healthy ecosystems in the local areas where MCE's solar projects are located. MCE will continue to evaluate the potential impacts of climate change on its portfolio so that adjustments to its procurement strategy can be made if needed.

### XI.4. Impacts During Public Safety Power Shut-off (PSPS) Events

PSPS events have both supply and demand side impacts. The experiences of MCE customers with wildfires and PSPS events over the last few years has led MCE to increase the focus of both its procurement as well as customer programs strategies on resiliency.

MCE assesses customer usage as a result of a PSPS event, to the extent possible with the data to which MCE has access, in real time and adjustments to supply are made accordingly. Generation resources that are located in the footprint of a PSPS event are necessarily taken offline, though MCE continues to explore ways to safely keep these resources online and serving customers. MCE is an active participant in the Commission's PSPS and microgrid proceedings[17] to help ensure that state policy as well as IOU and CCA operating protocols are aligned and result in minimal PSPS impacts in the future.

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[16] See https://www.mcecleanenergy.org/news/local-projects/pollinator-requirement/.
[17] R.18-12-005 and R.19-09-009, respectively.

### XI.5. Forest Biomass Procurement

In recent renewable Open Season requests for offers, MCE has not received offers from forest biomass generators. MCE's FIT program is available on a first-come, first-served basis, and is also technology-agnostic, however, MCE has not received any forest biomass applications. As MCE works toward a low emissions portfolio, MCE will be seeking non-emitting renewable technologies to contribute to its existing bioenergy resources already under contract.

## XII. Consideration of Price Adjustment Mechanisms

In the future, and consistent with SB 350 and SB 100, MCE will review the possibility of incorporating price adjustments in contracts with online dates more than 24 months after the date of contract execution. As noted in the ACR, such price adjustments could include price indexing to key components or to the Consumer Price Index.

## XIII. Curtailment Frequency, Forecasting, Costs

This Section responds to the questions presented in Section 5.13 of the ACR[18] and describes MCE's strategies and experience so far in managing the Agency's exposure to negative pricing events, overgeneration, and economic curtailment for MCE's region and portfolio of renewable resources.

### XIII.1. Factors Having the Most Impact on the Projected Increases in Incidences of Overgeneration and Negative Market Price Hours

Due in large part to the rapid increase in the amount of wind and solar generation that has been brought online throughout the western United States, the CAISO's balancing authority area has experienced an increasing frequency and magnitude of curtailment and negative pricing events. As of 2019, California had more than 12,300 MW of solar, 8,100 MW of behind-the-meter solar, and 5,900 MW of wind. This increased capacity results in discrete periods where the majority of

[18] ACR at 28-30.

load in the CAISO is served by solar and wind resources. The monthly maximum load served by wind and solar in the CAISO has averaged 60.2% over the past 3 years (March 2018 to March 2021), and in March of 2021 the monthly maximum load exceeded 83%.[19]

To address the resulting instances of over-supply, the amount of curtailment of wind and solar in the CAISO has significantly increased each year, totaling 187,000 MWh in 2015, 308,000 MWh in 2016, 358,000 MWh in 2017, 461,000 MWh in 2018, 961,000 MWh in 2019, and 1,587,497 MWh in 2020.[20] As of the end of May, the total curtailment of solar and wind to date in 2021 is already 1,062,270 MWh. Curtailment is typically the highest during the months of March, April, and May when hydroelectric generation is historically at its highest and California load is at its lowest. Years in which there is an above-average snowpack results in higher-than-average hydroelectric generation which exacerbates renewable generation curtailment. The table below summarizes solar and wind curtailment from January 2021 through May 2021.

**Table 2: Summary of CAISO Solar and Wind Curtailment January-May 2021**

| 2021 Data | Wind Curtailment (MWh) | Solar Curtailment (MWh) |
|---|---|---|
| January | 5,036 | 57,293 |
| February | 6,852 | 130,879 |
| March | 18,387 | 323,572 |
| April | 17,151 | 175,368 |
| May | 10,682 | 317,049 |
| Total Curtailment | 58,109 | 1,004,162 |
| Curtailment % | 0.65% | 6.69% |

[19] CAISO, Monthly Renewables Performance Report, March 2021, available at http://www.caiso.com/Documents/MonthlyRenewablesPerformanceReport-Mar2021.html.

[20] CAISO, Managing Oversupply, Wind and Solar Curtailment Totals, updated April 11, 2021, available at *http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.*

| | | |
|---|---|---|
| No. of Intervals Curtailed | 8,927 | 17,421 |
| Pct. of Intervals Curtailed | 20.5% | 40.1% |

The CAISO notes that the majority of renewable resource curtailment is "local and economic."[21] That means that curtailment was in response to congestion and was mitigated by supply that was willing to reduce its output based on price signals from the CAISO market.

CAISO system-wide 2021 curtailment amounts are higher than those realized by MCE to date. Thus far in 2021 through May, MCE has experienced 35,111.8 MWh of curtailment, which is just over 1% of MCE's RPS portfolio.

**XIII.2. Written Description of Quantitative Analysis of Forecast of the Number of Hours Per Year of Negative Market Pricing for the Next 10 Years**

MCE's scheduling coordinator agent, ZGlobal, has the capability to perform production cost analyses based on various input assumptions through 2030 to derive hourly market prices for energy and ancillary services. PLEXOS Integrated Energy Model is a commercial optimization engine that can simulate the economic commitment and dispatch used by the CAISO's day-ahead market processes which simultaneously optimizes energy dispatch and ancillary services capacity awards across the CAISO grid. In this way, the simulation will determine locational marginal prices and ancillary service marginal prices in the same manner the CAISO day-ahead market sets prices. ZGlobal has developed models using input assumptions that are based on common case inputs and planning guidelines from WECC, CAISO, Commission, and California Energy Commission ("CEC").

The key assumptions considered for the assessment included the impact of higher California renewable energy standards (60% RPS by 2030), planned gas-fired and nuclear

[21] CAISO, Market Performance Report, June 9, 2020, page 18, available at http://www.caiso.com/Documents/MarketPerformanceReportforApril2020.pdf.

generation retirements and adopted CEC demand forecasts which consider energy efficiency programs and increased behind-the-meter solar generation. Results are highly dependent upon input assumptions, primarily the level of new RPS generation, deployment of energy storage facilities, upgrades to CAISO-controlled transmission facilities and the ability to export energy from the CAISO to external balancing areas.[22]

In California, electricity prices are typically set by gas-fired resources operating on the margin. However, as increasing supplies of renewable energy are added to the system, there are periods where marginal prices are being set by zero or even negatively-priced resources. As a result, market prices have been trending downward, especially during seasons and periods of the day when loads are low and solar output is high. The modeling shows a continuation of the trend, with prices falling during the middle of the day and increasing in the morning and evening when gas-fired resources are needed to meet peak loads outside of the solar supply period. In short, prices as reflected by the CAISO's duck curve are expected to continue, with the amplitude of the valley and ramps dictated by the amount of energy storage available to smooth out the net supply.

### XIII.3. Experience, to Date, With Managing Exposure to Negative Market Prices and/or Lessons Learned from Other Retail Sellers in California

MCE closely monitors six separate locations that are indicative of renewable energy resources that are exposed to market prices and potential curtailment. Resources at those locations are bid into the CAISO markets and are curtailed when prices fall below individual resource's threshold prices. Weighted average prices for the generation at those locations are compared to weighted average prices at PG&E's Distributed Load Aggregation Point ("DLAP") to assess the impact of congestion on the resource's performance. In addition, the MWh of curtailment are

[22] More recently, load has become an important input variable with the onset of the COVID-19 pandemic and its effect on load. However, ZGlobal has not performed long-term studies to determine the impact of load on long-term market prices as there is not enough data to determine a suitable load trajectory.

logged.

These two metrics - weighted average price of the resources compared to that of the DLAP and MWh curtailed - are used to assess effectiveness of the resources in meeting MCE's RPS obligations at cost effective prices. If the resource's weighted average price is near the DLAP and it has been curtailed, then the reason for curtailment is system over-supply. If the resource's weighted average price diverges from the DLAP and it has been curtailed, then the reason for curtailment is local overgeneration that is contributing to congestion. This information is valuable feedback to MCE in locating potential future resources. If congestion and local oversupply is significant in certain areas, then MCE can determine by reviewing the CAISO's transmission planning documents whether transmission upgrades are planned to mitigate congestion that is observed with existing resources.

If curtailment is caused by congestion, the impact can be somewhat mitigated by obtaining CAISO Congestion Revenue Rights ("CRRs"), which MCE has done. However, CRRs are not a perfect hedge against congestion and cannot be relied upon to mitigate congestion and subsequent economic curtailment entirely.

### XIII.4. Direct Costs Incurred, to Date, for Incidences of Overgeneration and Associated Negative Market Prices

For calendar year 2021 through May, MCE's RPS portfolio has been exposed to negative market prices and experienced curtailment as summarized in the table below.

**Table 3: Summary of MCE RPS Resources Curtailment January-May 2021**

| Location | Day-Ahead Negative Prices | Real-Time Negative Prices | Curtailment (MWh) | Cost of Curtailment ($) |
|---|---|---|---|---|
| South P26 | -$0.91 | -$2.57 | 10.8 | -$302 |
| Fresno 1 | -$19.89 | -$55.85 | 34,704.0 | -$2,591,969 |

| | | | | |
|---|---|---|---|---|
| Fresno 2 | -$2.34 | -$3.50 | 320.0 | -$2,072 |
| North P26 | -$6.01 | -$5.06 | 15.2 | -$196 |
| Wind South P26 | -$12.27 | -$12.86 | 0.6 | $23 |
| Intertie (North) | -$0.18 | -$1.82 | 61.3 | -$2,513 |
| **Total** | **-$73.97** | | **35,111.8** | **-$2,597,076** |

The Day-Ahead and Real-Time Negative Price columns represent averages of negative prices by RPS geographic area when prices are negative for solar hours for solar resources and all hours for wind resources. The prices are averages based on resources within the area. Curtailment megawatt hour ("MWh") is the amount of energy that MCE RPS resources in the areas were curtailed from January 1 through May 31, 2021. "Cost of Curtailment" is the subsequent market cost of the curtailed energy.

### XIII.5. An Overall Strategy for Managing the Overall Cost Impact of Increasing Incidences of Overgeneration and Negative Market Prices

While curtailment is a viable renewable integration strategy that is generally more cost-effective than other options, there are potential negative consequences from excessive curtailment. Curtailment of solar and wind represents a lost opportunity to generate zero-GHG electricity, and excessive curtailment could impact the ability of the state to meet its environmental and energy policy goals. Additionally, these over-supply situations expose ratepayers to increased costs because their load serving entities must either economically curtail the generating resource (and often pay for the electricity that was not generated) or generate power and be exposed to negative prices.

MCE will consider the impact of curtailment and negative pricing on its portfolio and will factor potential curtailment into its long-term planning. Due to the difficulty in accurately forecasting curtailment, MCE will review the historical data on curtailment and negative pricing within regions where MCE may contract for generating resources. When MCE is evaluating new procurement opportunities, the potential amount of future curtailment will be one factor that MCE will consider. While MCE has not yet developed an individualized forecast of future curtailment, MCE will factor potential curtailment into its minimum margin of procurement (described in Section IX) and may also factor this consideration in future iterations of its Risk Assessment (Section VII). To the extent that MCE is engaged in renewable supply agreements which include curtailment provisions, it will take actions to limit the impacts of curtailment on its customers. During its current and future renewable contracting efforts, MCE will pursue contract terms that recognize and limit the potential financial impacts of negative pricing and give MCE greater flexibility to direct economic curtailment, if this becomes necessary.

## XIV. Cost Quantification

MCE has provided the Cost Quantification Table as Appendix E. Pursuant to the direction in the ACR, MCE has completed those cells in the Cost Quantification table that correspond to Table 2, Rows 1-5 in the ACR.

## XV. Coordination with Integrated Resource Planning Proceeding

The resources identified in this RPS Procurement Plan are consistent with the resources identified in MCE's 2020 IRP, which was submitted to the Commission for certification on September 1, 2020. As required by the ACR,[23] MCE includes the Table 4 below, which describes how MCE's 2021 RPS Procurement Plan conforms with the determinations made in the IRP Proceedings (R.16-02-007 and R.20-05-003).

[23] ACR at 32-35.

MCE notes that on June 17, 2021, Energy Division provided the draft Resource Data Template. The final Resource Data Template is expected to be released on/around July 1, 2021, with a related update required by August 31, 2021. Based on MCE's ongoing renewable contracting activities, it expects to provide related updates in the required Resource Data Template as well as other updates that may be required as part of the upcoming IRP process. As required, MCE will highlight the interrelationships of its RPS and IRP planning processes in a future iteration of this RPS Procurement Plan. The following table reflects MCE's most recent updates, as reflected in its Final 2020 RPS Procurement Plan, regarding RPS alignment with the IRP process.

**Table 4: RPS Alignment in MCE's IRP**

<table>
<tr><th>IRP Section Subsection</th><th colspan="2">RPS Alignment in IRP</th></tr>
<tr><td rowspan="2">III. Study Results<br>A. Conforming and Alternative Portfolios</td><td colspan="2">Retail sellers should explain how the RPS resources they plan to procure, outlined in their RPS Plan, will align with each of their Conforming Portfolios being developed in their 2020 IRP Plans for Commission approval and certification.[24] This explanation should include:</td></tr>
<tr><td>1. Existing RPS resources that the retail seller owns or contracts.<br>2. Existing RPS resources that the retail seller plans to contract with in the future.<br>3. New RPS resources that the retail seller plans to invest in.</td><td>As part of its 2020 IRP filing, MCE submitted two Preferred Conforming Portfolios that achieve its proportional share of both the 46 and 38 MMT GHG targets. Under each of these portfolios, new resources were added to MCE's currently contracted RPS resources to achieve the relevant GHG target as well as RPS procurement requirements, including the 65% long-term contracting requirement.<br>Description of Conforming Portfolios:</td></tr>
</table>

[24] LSEs will develop two Conforming Portfolios seeking Commission approval or certification in their 2020 IRP Plans. RPS resources should be described in the 46 MMT and the 38 MMT GHG target Conforming Portfolios. This requirement does not apply to LSEs' Alternative Portfolios.

| | | |
|---|---|---|
| | | • 46 MMT Conforming Portfolio: Portfolio that achieves MCE's proportional share of a 46 MMT statewide GHG target<br>o MCE observes that conformance with the 46 MMT Portfolio required emission ***increases*** (through 2030) relative to MCE's currently projected emission metrics, which were achieved by MCE (on a projected basis) ***reducing*** the assumed use of RPS resources<br>o As a result of this observation, MCE submitted the 46 MMT Portfolio as a planning/modeling exercise and compliance submission only and asked the Commission to use its 38 MMT Approved Conforming Portfolio instead<br>• 38 MMT Approved Conforming Portfolio: Portfolio that achieves an overall portfolio GHG target below MCE's assigned share of 2030 emissions (at 0.669 MMT, relative to MCE's assigned share of 0.846 MMT)<br>o The 38 MMT Approved Conforming Portfolio assumed the use of RPS resources currently reflected in MCE's supply portfolio<br>o The extent of RPS-eligible resources reflected in MCE's 38 MMT Approved Conforming Portfolio include: 20 MW biomass; 3 MW geothermal; 13 MW small hydroelectric; 465 MW wind; and 1,271 MW solar<br>o Of the previously noted resources reflected in MCE's 38 MMT Approved Conforming Portfolio, the following new capacity additions would be required: new |

| | | |
|---|---|---|
| | | hybrid resources totaling 690 MW solar/ 300 MW battery storage and new wind resources totaling 230 MW |
| **IV. Action Plan**<br>**A. Proposed Activities** | Retail sellers should describe how they propose to use RPS resources to implement both Conforming Portfolios. Narratives should include: | |
| | *1. Proposed RPS procurement activities as required by Commission decision or mandated procurement.*<br>*2. Procurement plans, potential barriers, and resource viability for each new RPS resource identified.* | To ensure compliance with its GHG and RPS targets, MCE plans to substantially rely on GHG-free and RPS-eligible resources while contributing to statewide reliability requirements and responsibly managing overall portfolio costs. This approach is generally consistent between the 46 MMT Conforming Portfolio and 38 MMT Approved Conforming Portfolio.<br>MCE's compliance with the IRP incremental procurement obligation required by D.19-11-016 will be met through a mix of resources currently under contract. The contracted set of resources totals 89.38 MW of September Net Qualifying Capacity, which slightly exceeds MCE's 87.5 MW incremental capacity requirement, and certain portions are already online with the required balance of such incremental capacity expected to be online by the noted August 1st deadlines in 2021, 2022 and 2023. Such incremental capacity is comprised of the following eligible resource types: natural gas (Sutter Energy Center), wind, solar, and landfill-gas-to-energy generation. These resources are further described in MCE's 2020 IRP and MCE's February 1, 2021, incremental procurement compliance filing.<br>As part of its 2020 Open Season procurement process, MCE also contracted for a hybrid resource, which is expected to provide additional RPS-eligible incremental capacity (under long-term contract) beyond the noted 89.38 MW currently under contract. |

| | | |
|---|---|---|
| | | MCE will also administer future Open Season procurement processes to fill outstanding resource needs required to meet portfolio specifications reflected in its 38 MMT Approved Conforming Portfolio. |
| **IV. Action Plan**<br>**B. Procurement Activities** | The retail seller should describe the solicitation strategies for the RPS resources that will be included in both Conforming Portfolios. This description should include: | |
| | *1. The type of solicitation.*<br>*2. The timeline for each solicitation.*<br>*3. Desired online dates.*<br>*4. Other relevant procurement planning information, such as solicitation goals and objectives.* | MCE will issue future solicitations, as described above in Section X, on a timeline that is appropriate for the resource development plan reflected in its 46 MMT Conforming Portfolio and 38 MMT Approved Conforming Portfolio and that will allow MCE to meet its internal as well as state-mandated RPS targets. MCE typically administers its annual Open Season procurement processes each Spring and, as part of such processes, may pursue additional resources that will be needed to fulfill resource specifications reflected in its 38 MMT Approved Conforming Portfolio.<br>As noted above, MCE also identified contracting opportunities with certain hybrid resources as part of its 2020 Open Season procurement process and such resources are expected to provide additional RPS-eligible incremental capacity (under long-term contract) beyond the noted 89.38 MW currently under contract. |
| **IV. Action Plan**<br>**C. Potential Barriers** | Retail sellers should provide a summary of the potential barriers to implementing both Conforming Portfolios as they relate to RPS resources. The section should include: | |
| | *1. Key market, regulatory, financial, or other resource viability barriers or risks associated with the RPS resources coming online in both retail* | MCE does not expect any procurement barriers to impede its future contracting for new renewable energy resources, but notes that even though a balanced, diverse RPS portfolio is desirable, the limited resource availability and lead time |

| | | |
|---|---|---|
| | *sellers' Conforming Portfolios.*<br><br>*2. Key risks associated with the potential retirement of existing RPS resources on which the retail seller intends to rely in the future.* | required for some technology types may necessitate planning flexibility. The key risk affecting MCE's 38 MMT Approved Conforming IRP Portfolio is reliance on new resources. While MCE has a highly successful track record of contracting with new-build renewable resources, there is always a limited risk of project failure.<br><br>Risks are far more limited with regard to MCE's 46 MMT Conforming Portfolio, as this portfolio would actually require the reduced use of planned RPS resources relative to MCE's internally adopted targets.<br><br>In consideration of MCE's existing renewable energy commitments, significant internal renewable energy procurement targets and the relatively manageable level of incremental RPS procurement that would be required to meet parameters of the 38 MMT Approved Conforming IRP Portfolio, MCE does not have any substantive concerns regarding its ability to fulfill achieve levels of renewable energy procurement that will be required to satisfy pertinent RPS mandates or IRP targets. |

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Respectfully submitted,

*/s/Sabrinna Soldavini*

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# Appendix A

## Redlined Version of Draft 2021 RPS Plan