FEBRUARY FILINGS

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
COMMENTS ON THE TRANSMISSION DEVELOPMENT FORUM
January 21, 2022

I. INTRODUCTION

The California Community Choice Association[1] (CalCCA) submits these comments on the Transmission Development Forum held on January 21, 2022. The information provided at the forum and in the workbooks posted on the website will offer significant value to load-serving entities, developers, and other parties tracking the status of transmission and generator interconnection projects. In these comments, CalCCA requests additional information that should be provided to enhance the ability for parties to track project statuses.

II. COMMENTS

CalCCA supports the California Independent System Operator's (CAISO's) plan to host the Transmission Development Forum and update the workbooks on a quarterly basis. This timeframe will allow for timely updates to the broader stakeholder audience on project statuses. The information provided in the forum and in the workbooks generally captures the right information needed by parties to evaluate high-level project statuses in one place. To further aid in tracking project statuses, CalCCA requests two additions to the information provided in the workbooks:

---

[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, 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, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

1. A column that identifies the previously expected in-service date from the last workbook to allow parties to more easily track changes from one quarterly update to the next; and
2. A column that lists any other transmission projects or generation interconnection network upgrade projects that are dependent on the project to allow parties to identify potential impacts changes to project status have on other projects.

III. CONCLUSION

CalCCA appreciates the opportunity to comment on the Transmission Development Forum and commends the CAISO, the California Public Utilities Commission, and the participating transmission owners for initiating this effort.

Date: February 4, 2022

(Original signed by)

Eric Little
Director of Regulatory Affairs
California Community Choice Association
(510) 906-0182 | eric@cal-cca.org

DOCKETED	
Docket Number:	21-OIR-03
Project Title:	2022 Load Management Rulemaking
TN #:	241465
Document Title:	California Community Choice Association Comments - on Proposed Amendments to the Load Management Standards
Description:	N/A
Filer:	System
Organization:	California Community Choice Association
Submitter Role:	Public
Submission Date:	2/7/2022 5:18:25 PM
Docketed Date:	2/7/2022

Comment Received From: California Community Choice Association
Submitted On: 2/7/2022
Docket Number: 21-OIR-03

on Proposed Amendments to the Load Management Standards

Additional submitted attachment is included below.

STATE OF CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of: 2022 Load Management Rulemaking	Docket No. 21-OIR-03

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED AMENDMENTS TO THE LOAD MANAGEMENT STANDARDS CONTAINED IN THE CALIFORNIA CODE OF REGULATIONS, TITLE 20

Evelyn Kahl
General Counsel and Director of Policy
Leanne Bober
Senior Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94520
(415) 254-5454
regulatory@cal-cca.org

February 7, 2022

STATE OF CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of: 2022 Load Management Rulemaking	Docket No. 21-OIR-03

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED AMENDMENTS TO THE LOAD MANAGEMENT STANDARDS CONTAINED IN THE CALIFORNIA CODE OF REGULATIONS, TITLE 20

The California Community Choice Association[1] (CalCCA) submit these Comments on the proposed *Amendments to the Load Management Standards Contained in the California Code of Regulations (CCR), Title 20* (Amendments), issued by the California Energy Commission (Commission) on December 22, 2021.

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

The Amendments require "utilities" to adopt hourly marginal cost rates, employing a very specific Commission-mandated methodology, to be inputted into the Commission's Market Informed Demand Automation Server (MIDAS) in the service of encouraging customer-supported load management. CalCCA supports the Commission's efforts; indeed, community choice aggregators (CCAs) continue to evaluate load-management tools for their customers, although these efforts are challenged by limited access to investor-owned utility (IOU) real-time

---

1 California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, 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, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

customer data. CalCCA further supports the general concept of a statewide automated system incorporating time and location-dependent signals, like MIDAS, as a tool to incentivize automation service providers to create products to automate demand flexibility. CalCCA parts company with the Commission, however, on the Commission's legal authority to mandate its prescriptive rate methodology for CCAs.

The Amendments step beyond the load management jurisdiction granted to the Commission under Public Resources Code (PRC) section 25403.5.[2] The statute, enacted in 1976, authorized the Commission to ensure that utilities were controlling their load before authorizing the construction of additional generating resources under its siting jurisdiction. The Commission's legal authority extends to "utilities," and arguably only those regulated by the California Public Utilities Commission (CPUC). Notably, in 1976 when the legislature granted jurisdiction under the statute, CCAs did not exist, and the Legislature has never amended the statute to include CCAs. Despite clear statutory language and consistent regulatory history, however, the Amendments expressly extend the marginal cost rate mandate to CCAs.

Not only do the Amendments apply the new standards to CCAs, but they expand the application of the load management standards and the definition of "utility" to include CCAs for purposes of all load management regulations located in Article 5 (sections 1621-1625).[3] These modifications therefore effectively apply to CCAs all existing load management standards, including sections 1622 (residential electric water heaters and air conditioners), 1624 (swimming pool filter pumps), and 1625 (non-residential load management standard)). Likewise, the expanded definition of "utility" to include CCAs will set a precedent for any future regulations promulgated under the 1976 statutory authority.

---

[2] Cal. Pub. Res. Code § 25403.5.

[3] Cal. Code of Regs, Title 20, Article 5, §§ 1621-1625.

The Amendments overstep the Commission's jurisdictional boundaries not only by including CCAs within the scope of regulations without legal authority but by mandating a specific rate methodology that infringes on CCA governing boards' exclusive ratemaking authority. Assembly Bill (AB) 117, enacted in 2002, established a regulatory structure in which CCA customers' rates are approved by their local governing boards.[4] Unlike IOUs, CCA rates are not overseen by the CPUC or, by the Final Staff Report's own admission, the Commission.[5] Despite these limitations, the Amendments step squarely into the ratemaking arena, requiring CCAs to implement a very specific rate methodology and giving the Commission, not CCA governing boards, the right to impose injunctive relief or penalties on CCAs that do not comply.

The Commission attempts to justify this overreach on several grounds. First, it claims, unpersuasively, that its actions are not ratemaking. A quick glance at section 1623(a)(1) of the Amendments, which prescribes the rate methodology and the required rate elements, proves otherwise. Second, it claims that the Legislature intended for CCAs to be included within the scope of the statute by referencing utility "service territories." This rationale ignores the fact that the statute was enacted in 1976, long before CCAs were authorized in 2002, and has never been amended to include them. Third, it claims that, practically, it is important to include CCAs to optimize the benefits of MIDAS. While CCA participation will no doubt enhance the usefulness of MIDAS, practical observations do nothing to change legal authority.

To resolve these unlawful infringements on CCA rate autonomy and operations, CalCCA requests the following revisions to the Amendments:

---

4 AB 117, Stats. 2002; ch. 838 (codified at Cal. Pub. Util. Code § 366.2(c)(1)).

5 Herter, Karen and Gabin Situ, 2021. *Analysis of Potential Amendments to the Load Management Standards: Load Management Rulemaking, Docket Number 19-OIR-01.* California Energy Commission. Publication Number: CEC-400-2021-003-SF (Final Staff Report) at 17 ("[s]pecific to rate structure, the CEC does not have exclusive or independent authority. For example, rates proposed in compliance with the load management standards are subject to approval by . . . CCA governing boards . . . .").

- Apply the marginal cost rate requirements to CCAs on a *voluntary* basis;
- Leave approval of any CCA marginal cost rate to the CCA governing boards; and
- Limit the application of the load management standards on CCAs and remove CCAs from the definition of "Utility" to avoid the inadvertent imposition of other existing and future load management standards on CCAs.

With these changes, CalCCA looks forward to supporting the Commission's foundational goal of encouraging customer-supported load management and further developing MIDAS in a manner that best promises effectiveness for CCA customers and responds to the directives of CCA governing boards.

II. THE AMENDMENTS MANDATE A SPECIFIC RATE METHODOLOGY, REQUIRING ADOPTION OF HOURLY LOCATIONAL MARGINAL COST RATES WITH REQUIRED ELEMENTS FOR EACH CUSTOMER CLASS

The Amendments mandate that CCAs (in addition to the IOUs and publicly-owned electric utilities (POUs)) *develop and submit to their rate approving body within one year of the effective date of the regulations at least one marginal cost rate for each customer class*.[6] "Marginal cost" or "locational marginal cost" is defined as "the change in current future electric system cost that is caused by a change in electricity supply and demand during a specified time interval at a specified location."[7] The Amendments specify the elements of the marginal cost rates and require the following calculation:

> Total marginal cost shall be calculated as the sum of the marginal energy cost, the marginal capacity cost (generation, transmission, and distribution), and any other appropriate time and location dependent marginal costs on a time interval of no more than one hour. Energy cost computations shall reflect locational marginal cost pricing as determined by the associated balancing authority, such as the California Independent System Operator, the Balancing Authority of Northern California, or other balancing authority. Marginal cost computations shall reflect the variations in the probability and value of system reliability of each component (generation, transmission, and distribution). Social cost

[6] Amendments § 1623(a).

[7] *Id.,* at § 1623(c)(7).

> computations shall reflect, at a minimum, the locational marginal cost of associated greenhouse gas emissions.[8]

Failure to comply with the proposed regulations can trigger the Executive Director filing a complaint with the Commission or seeking injunctive relief.[9]

The regulation treads on the ratemaking authority of the CPUC, POU boards, and CCA governing boards. Not only does it mandate the high-level methodology that must be employed – marginal cost vs. embedded cost – it goes into meaningful detail regarding the calculation of the rate. As explained below, by enveloping CCAs into the application of the load management standards, the Amendments have the effect of unlawfully mandating that CCAs adopt particular rates. It specifies the rate elements, including transmission, generation, and distribution costs. It further specifies the frequency of change in the rate to one hour or less. It also specifies the source of the marginal costs – in the case of CCAs, the California Independent System Operator (CAISO) locational marginal cost. Finally, it specifies that the rate must be developed separately for each customer class. The mandated detail goes far beyond the scope of a "rate structure."

III. THE COMMISSION SHOULD REVISE THE AMENDMENTS TO ALLOW CCA PARTICIPATION IN THE PROPOSED RATE PROGRAM ON A VOLUNTARY BASIS, LEAVING RATE APPROVAL TO CCA GOVERNING BOARDS

The Commission promulgates the Amendments under the Warren-Alquist Act, PRC section 25403.5. However, section 25403.5 does not grant the Commission authority to impose standards for electrical load management on CCAs and, particularly, does not impose on CCAs those standards that include "adjustments in rate structure." Indeed, the Final Staff Report accompanying the Amendments *acknowledges* the lack of ratemaking authority over CCAs.[10]

---

8 *Id.,* at § 1623(a)(1).

9 *Id.,* at § 1621(f) (allowing the Executive Director to file a complaint with the Commission or seek injunctive relief for, among other reasons, violation of the provisions of the load management regulations).

10 Final Staff Report at 16-17.

The Final Staff Report attempts, however, to rationalize shoe-horning CCAs into the program on grounds that (1) the Amendments propose a "rate structure," rather than a rate, (2) CCAs provide service within the service area of the IOUs, and (3) including CCA customers is necessary to ensure the success of the load management program.[11] As set forth more fully below, none of these arguments can cure the Commission's lack of jurisdiction to *mandate* CCA adoption of a specific rate design. Any CCA inclusion in the program therefore must be on a voluntary basis.

A. Public Resources Code Section 25403.5 Does Not Grant the Commission Authority to Mandate Application of the Load Management Standards to CCAs

PRC section 25403.5 was enacted in 1976 with the purpose of mandating that a utility certify its compliance with load management standards before the Commission would approve a new generation project.[12] Subsection 25403.5(a) requires that the Commission "adopt standards by regulation for a program of electrical load management for each *utility service area*."[13] PRC section 25118 defines a "service area" as "any contiguous geographic area serviced by the same electric utility."[14] The PRC does not define "Utility," and CCAs are not included in that classification or definition either in the PRC or the Public Utilities Code. Among the techniques the Commission is to consider for load management include "[a]djustments in rate structure to encourage use of electrical energy at off-peak hours or to encourage control of daily electrical load."[15]

---

11 *Id.*

12 Cal. Pub. Res. Code § 25403.5 (1976) (amended in 1980 to eliminate a penalty clause for failure to comply, and to add § 25300 to establish a forecast reporting requirement for electric utilities, all of which was subsequently revised by 2002 through Senate Bill (SB) 1389 (repealing § 25300) to create reporting requirements concerning load forecasts through the Integrated Energy Policy Report (IEPR) process).

13 *Id.*, at § 25403.5(a).

14 *Id.*, at § 25118.

15 *Id.*, at § 25403.5(a)(1).

Of note are the provisions of section 25403.5 that affirm that the load management program was intended only for CPUC-regulated utilities. For example, the statute states that "[c]ompliance with . . . adjustments in rate structure *shall be subject to the approval of the Public Utilities Commission in a proceeding to change rates or service*."[16] The CPUC's jurisdiction extends to IOUs, and the CPUC has acknowledged its lack of ratemaking authority over CCAs.[17] Therefore, on its face the statute explicitly suggests its exclusive application to only CPUC-regulated utilities. Furthermore, section 25403.5 mandates that "[a]ny expense or any capital investment required of a utility by the standards shall be an allowable expense or an allowable item in the utility rate base and *shall be treated by the Public Utilities Commission as allowable in a rate proceeding*."[18] Again, the clear language of the statute evidences its applicability to only CPUC-regulated utilities.

Given this statutory backdrop, the Final Staff Report acknowledges the inability to include CCAs within its direct statutory reach. To get around this fact, the Final Staff Report concludes that because CCAs operate as load-serving entities (LSEs) *within the electric utility service areas*, the Amendments must apply to CCA customers to ensure the programs' success:

> The Warren-Alquist Act was adopted prior to the creation of CCAs. Nevertheless, CCAs operate within the geographical service territories of electric utilities. So, load management standards apply to CCAs that provide electricity to customers within these service areas. *For load management standards to function in a manner that meets the intent of the statute, the standards need to apply to most electric customers.* To the extent CCA service is the default provider and continues to expand in

---

16 *Id.*

17 *See, e.g.,* Decision (D.) 05-12-041, *Decision Resolving Phase 2 Issues on Implementation of Community Choice Aggregation Program and Related Matters,* Rulemaking (R.) 03-10-003 (Dec. 15, 2005) at 9-10, 42 (noting that "existing law protects CCA customers" by subjecting "[e]ntities of local government, such as CCAs, . . . to numerous laws that will have the effect of protecting CCA customers and promoting accountability by CCAS," and that the CPUC has "consistently treated CCAs as stand-alone operations with ratemaking discretion").

18 Cal. Pub. Res. Code § 25403.5(b).

> California, *any other interpretation would diminish the effectiveness of the proposed amendments to the load management standards and defeat the purpose of the statute.*[19]

According to this logic, the Commission's jurisdiction would extend to any matters, including unlawful rate mandates on CCAs, necessary to ensure the success of the load management standards. In other words, the Commission is using the end (success of the load management standards), to justify the means (assertion of jurisdiction over CCAs), even absent its authority to do so.

B. The Commission's Rate Mandate Infringes on the Ratemaking Autonomy of CCA Governing Boards Prescribed in AB 117

AB 117 passed in 2002 to enable local governments to establish CCAs to purchase electricity on behalf of residents and businesses in place of investor-owned utilities.[20] CCAs have independent control over their procurement, for which they are authorized "to group retail electricity customers to solicit bids, broker, and contract for electricity and energy services for those customers."[21] AB 117 incorporates an overall statutory and regulatory framework based on the principle of CCA operational and procurement autonomy. As part of CCA service, an implementation plan adopted by the governing board of a CCA is certified by the CPUC detailing operational processes including ratesetting and "[p]rovisions for disclosure and due process in setting rates and allocating costs among participants."[22] In short, CCA governing boards have autonomy and independence from regulatory oversight, including the CPUC or this Commission, over their rate-setting and procurement on behalf of their customers.[23] Critically, the CPUC has not mandated particular rates for CCA customers.

---

19 Final Staff Report at 17 (emphasis supplied).
20 AB 117, Stats. 2002; ch. 838 (codified at Cal. Pub. Util. Code § 366.2).
21 Cal. Pub. Util. Code § 366.2(c)(1).
22 *Id.*, at § 366.2(c)(3)(B)-(C).
23 *See, infra,* n. 17.

After asserting its authority to include CCAs, the Final Staff Report correctly notes that *"[s]pecific to rate structure, the [Commission] does not have exclusive or independent authority."*[24] The Report also states that "rates proposed in compliance with the load management standards are subject to approval by the CPUC, *CCA governing boards*, and POU governing boards."[25] Given the Commission's lack of ratemaking authority, the Report states that "the proposed load management standards address *overarching structural features, while the detailed mechanics of the rate design are left to the utilities and their regulators or governing boards*."[26]

Despite these statements, the proposed Amendments *mandate* the development and submission of particular locational marginal cost rates for each customer class, with review, approval, and enforcement authority provided to the Commission.[27] In fact, subsection 1623(a)(1) even mandates the exact elements of how the CCA is to calculate "total marginal cost" in its rates. The Amendments go far beyond a "rate structure," and instead require CCA local governing boards to approve a particular rate design and calculation for each customer class of a CCA, with Commission enforcement consequences for failure to do so. While the Final Staff Report correctly notes that CCA governing boards have exclusive authority to set rates, the actual amended regulations improperly infringe on that authority and unlawfully impose prescriptive rate mandates outside of the jurisdiction of the Commission. As a result, the Amendments must be revised to remove the rate mandates, and instead provide recommendations to support the Commission's load management program.

---

24 Final Staff Report at 17 (emphasis supplied).
25 *Id.* (emphasis supplied).
26 *Id.* (emphasis supplied).
27 Amendments §§ 1621(d)-(f) (mandates for submissions to Commission for approval), 1623(a) (mandate requiring development of marginal cost rates (as calculated according to the subsection 1623(a)(1) for each customer class)).

C. The Commission Should Recommend Voluntary Adoption of Marginal Cost Rate to CCAs to Further its Load Management Goals

CCAs support the Commission's goals for load management, and generally support time-based rates uniquely developed by CCAs pursuant to their ratemaking autonomy and which suit each CCA's local needs. However, CCAs are currently unable to create time-based rates given the lack of access to necessary data to support such rates that would need to be provided by the IOU in the territory that the CCA operates. CCAs are hopeful that such data will be made available in the future and are amenable to rate *recommendations* provided by the Commission to support the load management standards. Accordingly, the Commission should modify the Amendments, consistent with the proposed language in Appendix A, attached hereto, to clarify that the proposed rate structures and tariffs are *recommendations* for CCAs, rather than *mandates*. The governing boards of each CCA will then retain their exclusive authority, and discretion, to adopt the recommended rates when technically feasible and cost effective for specific rate classes.

IV. THE COMMISSION SHOULD REVISE THE AMENDMENTS TO LIMIT APPLICATION OF THE REGULATIONS TO CCAS AND REMOVE CCAS FROM THE DEFINITION OF "UTILITY"

The Amendments to section 1621 would add CCAs into the "Application" of Article 5 (sections 1621-1625), as well as add CCAs into the definition of "Utility." For the same reasons described in section III., above, the Commission must revise the Amendments as set forth in Appendix A to limit the application of Article 5 on CCAs and remove CCAs from the definition of "Utility." The Commission does not have the requisite authority under section 25403.5 to mandate broad load management programs for CCAs.

In addition, as currently drafted the Amendments would inadvertently apply all current and future sections of Article 5 on CCAs, even those not being considered in this rulemaking. By adding CCAs into the "Application" of Article 5, as well as adding CCAs into the definition of "Utility," CCAs would be mandated to comply with sections 1622 (utility peak load cycling programs applicable to residential electric water heaters and electric air conditioners), 1624 (running of swimming pool filter pumps during off-peak hours), and 1625 (load management standards for non-residential customers). Imposing the requirements of sections 1622, 1624, or 1625 on CCAs was never contemplated in the pre-rulemaking phase or in the Final Staff Report. Therefore, the Amendments should be revised as set forth in Appendix A to limit the application of Article 5 to exclude CCAs.

V. THE COMMISSION CAN ACHIEVE ITS LOAD MANAGEMENT GOALS BY RECOMMENDING VOLUNTARY ADOPTION OF RATES BY CCAS TO POPULATE THE MIDAS DATABASE

From a high level, the goals of the MIDAS database and the Commission's proposed load management program are compelling – to "form the foundation for a statewide system of granular time and local dependent signals that can be used by automation-enabled loads to provide real-time load flexibility on the electric grid."[28] The Commission likely committed extensive resources to the creation of the MIDAS system, a central, statewide machine-readable database of rates and other grid signals accessible to customers and third-party automation service providers. Central to the success of the MIDAS database, however, is the adoption by "Utilities" of hourly locational marginal rates to populate the MIDAS database. Without those rates, the Commission believes that its hopes for the MIDAS system cannot be fulfilled, and third-party automation service providers will lack the incentive to develop demand response products to interact with the MIDAS database.

---

28 Final Staff Report, Abstract at iii.

The problem with this "tail wagging the dog" strategy is that forcing uniform rate design on a diverse group of LSEs subject to unique legal, regulatory, and commercial constraints is problematic and complex. With respect to CCAs, the Commission simply lacks the legal authority to require the adoption of the rates. In addition, from a practical and commercial perspective, each CCA has unique characteristics that contribute to any decision to adopt particular rates for customers.

In short, the Commission *cannot* force fit a particular rate on a CCA to satisfy the requirements of its MIDAS system. Instead, the Commission *can* recommend voluntary adoption of such rates to populate the MIDAS, with the promise to LSEs such as CCAs of a method to allow their customers to access this simplified approach to demand response. CalCCA therefore encourages the Commission to adopt the modifications to the Amendments as set forth in Appendix A.

VI. CONCLUSION

CalCCA appreciates Commission staff's efforts in Docket 21-OIR-03 and looks forward to further collaboration on this topic.

Respectfully submitted,

Evelyn Kahl

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

February 7, 2022

APPENDIX A
CalCCA Redline of Amendments (in green)

Section 1621 General Provisions

(b) Application. Each of the standards in this article applies to the following electric utilities: Los Angeles Department of Water and Power, San Diego Gas and Electric Company, Southern California Edison Company, Pacific Gas and Electric Company, and Sacramento Municipal Utility District.~~, as well as~~ In addition, the standards set forth in subsection 1623(e) of this Article apply to any Community Choice Aggregator (CCA) operating within the service area and receiving distribution services from the foregoing electric utilities. The ~~California Energy~~ Commission has found these standards to be technologically feasible and cost-effective when compared with the costs for new electrical capacity for the above-named electric utilities~~., including any customers of CCAs operating within the service area of such electric utilities~~.

(c) Definitions. In this article, the following definitions apply:

~~(1)~~(15) "Utility" means those electric utilities to which the sections of this article apply, as specified in subsection (b). A~~, and any~~ CCA serving customers within the service area of any of those specified electric utilities is not a Utility.

Section 1623 Load Management Tariff Standard

(e) Electricity Rates and CCAs. CCA are encouraged, to the extent cost-effective, technologically feasible, and consistent with the directives of their local governing board, to:

(1) Develop and present to its governing board hourly or sub-hourly marginal cost (to be calculated in accordance with section 1623(a)(1)) rate(s) for (a) particular customer class(es) compatible with the goals of the Commission's load management standards set forth in this Article:
(2) Provide the Commission with informational copies of the rates approved by a CCA's local governing board;
(3) Upload the approved rate to the Commission's MIDAS database
(4) Allow its customers access to rate information application to the customer with a single RIN assigned by the CCA;
(5) Contribute information to the Utility single statewide tool for authorized rate data access by third parties, as set forth in section 1623(c); and
(6) Encourage mass-market automation of load management through information and programs, including appropriate educational outreach to inform CCA customers of the rate tariff, and how the tariff may provide bill savings.

Nothing in this subsection (e) shall subject CCAs to the requirements of sections 1621(d)-(h), or 1623(a)-(d) of this Article.

FILED
02/14/22
04:08 PM

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.21-10-002

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON PHASE 2 WORKSHOP AND PROPOSALS

Evelyn Kahl,
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94520
(415) 254-5454
regulatory@cal-cca.org

February 14, 2022

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page

California Public Utilities Commission Proceedings

SUMMARY OF RECOMMENDATIONS

- CalCCA supports the Commission conducting an LOLE study to inform the PRM;
- The Commission should include updated forced outage estimates as inputs into the LOLE;
- CalCCA supports using LOLE analysis to update the PRM as opposed to ad hoc increases to the PRM that are not based on robust analysis and not officially incorporated into the RA program; and,
- The PRM should be reviewed after a reasonable period of time or upon significant changes to the inputs.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.21-10-002

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON PHASE 2 WORKSHOP AND PROPOSALS

The California Community Choice Association[1] (CalCCA) submits these Comments in response to the *Assigned Commissioner's Scoping Memo and Ruling* (Ruling), filed on December 2, 2021.

I. INTRODUCTION

CalCCA supports the California Public Utilities Commission (Commission) conducting a Loss of Load Expectation (LOLE) study to inform modifications to the planning reserve margin (PRM) to ensure it meets a targeted level of reliability. The Commission indicated Energy Division will issue an LOLE study and PRM proposal within this phase of the Resource Adequacy (RA) proceeding in the near future.[2] The LOLE study issued by Energy Division should provide valuable insight into how the PRM needs to be updated. The California

---

[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, 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, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] *Email Ruling on Loss of Load Expectation Study*, Feb. 3, 2022 (R.21-10-002).

Independent System Operator (CAISO) and San Diego Gas & Electric Company (SDG&E) also offered proposals related to the PRM. These comments offer recommendations based on the CAISO's and SDG&E's PRM proposals.

In summary, CalCCA supports the Commission conducting an LOLE study to inform the PRM and:

- The Commission should include updated forced outage estimates as inputs into the LOLE;
- CalCCA supports using LOLE analysis to update the PRM as opposed to ad hoc increases to the PRM that are not based on robust analysis and not officially incorporated into the RA program; and,
- The PRM should be reviewed after a reasonable period of time or upon significant changes to the inputs.

II. CALCCA SUPPORTS THE COMMISSION CONDUCTING AN LOLE STUDY TO INFORM THE PLANNING RESERVE MARGIN

A. The Commission Should Include Updated Forced Outage Estimates as Inputs into the LOLE

The CAISO proposes the Commission update the PRM based on an updated LOLE study including an updated forced outage rate of at least 7.5 percent to align with industry observed forced outage rates and account for extreme weather.[3] 7.5 percent is generally consistent with the forced outage data presented by the CAISO.[4] The Commission should use this updated forced outage estimate as an input into the LOLE study to determine the appropriate PRM as the CAISO suggests,[5] and not as an adder to the PRM. Using the 7.5 percent as both an input on the supply side (to calculate dispatch of generators in the LOLE study) and on the demand side (as

---

[3] *Phase 2 Proposals of the California Independent System Operator Corporation*, Jan. 21, 2022, R.21-10-002 (CAISO Proposal), at 5.

[4] *Unforced Capacity Evaluation Proposal*, CPUC Track 3B.2 Proceeding: Implementation Workshop, CAISO, Jan. 19, 2021: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-9-ucap-proposal_caiso.pdf.

[5] CAISO Proposal at 5.

an adder to the final PRM that load-serving entities (LSEs) must meet in their RA showings) would essentially over-count the effects of outages.

B. CalCCA Supports Using LOLE Analysis to Update the PRM as Opposed to Ad Hoc Increases to the PRM that are not Based on Robust Analysis and not Officially Incorporated into the RA Program

SDG&E explains that recent reliability challenges have resulted in the Commission making interim adjustments to the PRM not supported by LOLE analysis and suggests that going forward, the PRM should be developed in the RA proceeding through an annual LOLE study.[6] The CAISO also proposes the Commission phase out the use of an "effective" PRM, in favor of an official PRM update because the CAISO cannot exercise its backstop authority to cure for "effective" PRM deficiencies and non-RA capacity used to meet an "effective" PRM is not subject to CAISO RA rules, including the Resource Adequacy Availability Incentive Mechanism (RAAIM) and must-offer obligation.[7]

CalCCA understands the "effective" PRM to be one in which an entity believes that elements that are inputs to reliability have changed and as a result, the level of resources needed to meet reliability have also changed. Such a change can be effectuated by a new LOLE study which would account for the newly observed data. It can also be addressed by simply adjusting the PRM on the basis of the hypothesis without addressing the actual LOLE impact. This is more likely to be done in times when performing the necessary LOLE study may not occur in time for procurement to address the reliability need that may occur. For example, recent summer reliability procurement orders first used an "effective" 17.5% PRM for 2021 and 2022[8] and then

---

6 *San Diego Gas & Electric Company (U 902 E) Phase 2 Implementation Track Proposal*, Jan. 21, 2022, R.21-10-002 (SDG&E Proposal), at 2.

7 CAISO Proposal at 6.

8 *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022* (R.20-11-003), Mar. 25, 2021.

used an "effective" 20-22.5% PRM for 2022 and 2023[9] to order IOU procurement. Since this ruling is addressing the reliability need with sufficient time to address a more informed PRM through LOLE, the Commission should do so. This will require fewer "effective" types of decisions to be made.

SDG&E and the CAISO correctly call for the Commission to end the practice of effectively modifying the PRM in the short-term without robust analysis in favor of informing the PRM through advanced planning and well-vetted LOLE studies. This will allow LSEs sufficient lead time to conduct orderly procurement of RA to meet reliability needs. Therefore, CalCCA supports an official PRM update informed by an LOLE study vetted by stakeholders in favor of continuing the practice of "effective" PRM updates.

C. The PRM Should be Reviewed After a Reasonable Period of Time or Upon Significant Changes to the Inputs

SDG&E proposed performing the LOLE study on an annual basis and updating the PRM for each RA compliance year based on the results of the study.[10] If an LOLE study can be easily performed and vetted on an annual basis timely and cost-effectively, the Commission should adopt SDG&E's proposal for an annual LOLE study and PRM update. However, the Commission must determine if performing an annual LOLE analysis and allowing time for robust vetting will be overly burdensome and if conducting an LOLE study each year will not result in substantial PRM changes year over year. If that is the case, the Commission could either determine a more feasible amount of time to regularly review the PRM (*e.g.*, every two years) or determine a threshold that would trigger a new LOLE study based on changes in inputs (*i.e.*, load

---

9 *Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023* (R.20-11-003), Dec. 2, 2021.

10 SDG&E Proposal at 1.

forecast changes, resource retirements, or counting rule changes). These alternatives will ensure the PRM remains up to date in the event an annual PRM review process is not feasible.

As articulated in CalCCA's Comments in this OIR[11], the Commission must consider the PRM within the context of the RA reform track as the outcome of the reform track will likely impact the appropriate level of the PRM. For example, resource counting rules proposed in the reform track could impact the level of PRM required to achieve a targeted level of reliability. The PRM would also need to be revisited in the context of UCAP if forced outages are incorporated into resources' capacity values. The PRM must be considered in conjunction with the structural changes in the reform track to ensure the RA program results in the targeted level of reliability under the new structural framework.

III. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of these comments and looks forward to an ongoing dialogue with the Commission and stakeholders on the appropriate PRM following the issuance of the Energy Division's LOLE study.

Respectfully submitted,

Evelyn Kahl

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

February 14, 2022

---

11 *California Community Choice Association Comments on Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations* (R.21-10-002), Nov. 1, 2021, at 5.

California Community Choice Association

SUBMITTED 02/22/2022, 04:12 PM

Contact

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

1. Please provide your organization's overall comments on the Draft 2021-2022 Transmission Plan Feb 7, 2022 stakeholder call discussion:

The California Community Choice Association[1] (CalCCA) appreciates the California Independent System Operator's (CAISO's) work on the 2021-2022 Transmission Plan. In these comments, CalCCA makes the following recommendations for the CAISO to incorporate into the 2022-2023 Transmission Plan.

Consideration of Long-Lead-Time Resources

It is critical the Transmission Planning Process (TPP) reflect current geographic and market information to allow for the development of significant amounts of cost-effective resources in line with the California Public Utilities Commission's (CPUC's) procurement requirements and to avoid stranded resource investments. CalCCA's Reply Comments[2] to the CPUC's Proposed Decision Adopting the 2021 Preferred System Plan[3] urged the CPUC to update the PSP Core Portfolio to reflect the availability and location of cost-effective resources (*i.e.*, "long-lead-time resources" that can fulfill the CPUC's Mid-term Reliability (MTR) requirements), including geothermal resources, in Nevada.

The 20-Year Outlook includes roughly 2 gigawatts (GW) of geothermal from IID, but only 320 megawatts (MW) of geothermal in southern Nevada. The busbar mapping in the PSP Decision[4] increases the amount of geothermal in southern Nevada to 440 MW. At a minimum, the CAISO should reflect this increase in their 2022-2023 TPP and in the next iteration of the 20-Year Transmission Outlook. However, given the timeframe of the 20-Year Transmission Outlook, the CAISO should include the full potential for growth in Nevada geothermal that far exceeds 440 MW. CalCCA requested the CPUC update the Preferred System Plan (PSP) to plan for at least 2,000 MW of further incremental renewable resources imported from Nevada. The CAISO should study the full 2,000 MW, requested by CalCCA in its comments to the PSP, in the 2022-2023 TPP cycle and the next iteration of the 20-year Transmission Outlook to allow the CAISO to evaluate necessary import expansion or transmission upgrades needed to deliver Nevada geothermal resources to California.

Given the significant resource development opportunities out-of-state, the CAISO should also provide additional transparency on how transmission upgrades identified in the TPP will affect maximum import capability (MIC) needed for load-serving entities (LSEs) to show resources out of state as resource adequacy (RA). LSEs must secure

MIC at the right nodes to be able to use out-of-state resources like Nevada geothermal to provide RA capacity. Understanding how the TPP and 20-year plan will affect import capability at specific nodes would significantly improve LSEs' ability to make decisions around contracting and arranging transmission for potential projects to serve California load as RA. This transparency will minimize the risk of planned projects failing to materialize and minimize costs associated with the uncertainty around available MIC.

Policy-Driven Assessments in Local Areas

CalCCA appreciates the CAISO's consideration of local area needs in its policy-driven assessments. CalCCA reiterates its position from previous comments that the CAISO should consider how to incorporate policy-driven assessments in local areas in the next TPP cycle. As the fleet of resources evolves, the potential for a local constraint to become binding will increase. A policy-driven assessment should be performed to identify transmission upgrades or alternatives that facilitate retirements for fossil fuel plants on a timeline that maintains reliability in local areas and makes progress on state environmental requirements including minimizing air emissions in disadvantaged communities.[5]

In the next TPP cycle, the CAISO should incorporate a policy-driven assessment into its evaluation of transmission upgrades or alternatives needed to address local needs. As the state works towards achieving a zero-carbon electric system by 2045, more renewable resources and storage will necessarily come online creating opportunities for existing fossil fuel plants to retire. However, if an existing fossil fuel plant is in a locally constrained area, the resource retirement will not occur until the transmission constraint is eliminated or enough carbon-free resources are built in the local area to fulfill the local need. This could result in delays in meeting environmental standards if transmission capacity or other alternatives are not built to address the local need. The CAISO should consider transmission upgrades and potential alternatives to alleviate local area transmission constraints that would allow fossil fuel plants to retire to meet the State's green-house gas (GHG) mandate reliably.

---

[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] *California Community Choice Association Reply Comments on the Proposed Decision Adopting 2021 Preferred System Plan*, Jan 19, 2022 (Rulemaking (R.) 20-05-003): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M443/K010/443010067.PDF.

[3] *Proposed Decision Adopting 2021 Preferred System Plan*, Dec 22, 2021 (R.20-05-003): https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=434547053.

[4] *Decision Adopting 2021 Preferred System Plan, Attachment A Modeling Assumptions 2022-2023 TPP*, Feb. 10, 2022 (R.20-05-003) (PSP Decision): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K485/451485713.PDF

[5] *See* Public Utilities Code § 454.52(a)(1)(h).

2. Comment on chapter 1 Overview of the Transmission Planning Process:

CalCCA has no additional comments at this time.

3. Comment on chapter 2 Reliability Assessment – Study Assumptions, Methodology and Results:

CalCCA has no additional comments at this time.

4. Comment on chapter 3 Policy-Driven Need Assessment:

CalCCA has no additional comments at this time.

5. Comment on chapter 4 Economic Planning Study:

CalCCA has no additional comments at this time.

6. Comment on chapter 5 Interregional Transmission Coordination:

CalCCA has no additional comments at this time.

7. Comment on chapter 6 Other Studies and Results:

CalCCA has no additional comments at this time.

8. Comment on chapter 7 Special Reliability Studies and Results:

CalCCA has no additional comments at this time.

9. Comment on chapter 8 Transmission Project List:

CalCCA has no additional comments at this time.

California Community Choice Association

SUBMITTED 02/22/2022, 04:21 PM

Contact

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

1. Please provide your organization's overall comments on the Draft 20-Year Transmission Outlook Feb 7, 2022 stakeholder call discussion:

The California Community Choice Association[1] (CalCCA) applauds the California Independent System Operator's (CAISO's) development of the 20-year Transmission Outlook. This work will be critical in ensuring the state is prepared to meet Senate Bill (SB) 100[2] goals that require renewable energy and zero-carbon resources to supply 100 percent of electric retail sales to end-use customers by 2045. CalCCA commends the CAISO on its collaboration with other agencies, particularly around land use mapping. In the next Transmission Planning Process (TPP) cycle and future iterations of the 20-year Transmission Outlook, the CAISO should consider transmission needed to import out-of-state geothermal resources from Nevada into California.

---

[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] *Senate Bill 100 California Renewables Portfolio Standard Program: Emissions of Greenhouse Gases*: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.

2. Comment on chapter 1 Introduction:

CalCCA has no additional comments at this time.

3. Comment on chapter 2 Coordination with State Agencies:

CalCCA commends the CAISO on its collaboration with the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) in the Integrated Resource Plan (IRP), SB 100, and Integrated Energy Policy Report (IEPR) processes. In particular, CalCCA supports the 20-year Transmission Outlook's consideration of key environmental and land use impacts provided by the CEC. By incorporating these considerations into transmission planning, the CAISO, the CPUC, and the CEC can help steer projects to less sensitive areas and avoid potentially serious delays or cancellations of transmission projects needed to integrate future resource procurement.

4. Comment on chapter 3 Process and Inputs:

CalCCA has no additional comments at this time.

5. Comment on chapter 4 Integration of Resources:

In these comments, CalCCA reiterates its comments to the Draft 2021-2022 Transmission Plan on sufficiently considering the opportunities provided by out-of-state long-lead-time resources, which state:

> It is critical the TPP reflects current geographic and market information to allow for the development of significant amounts of cost-effective resources in line with CPUC procurement requirements and to avoid stranded resource investments. CalCCA's Reply Comments[1] to the CPUC's Proposed Decision Adopting the 2021 Preferred System Plan[2] urged the CPUC to update the Preferred System Plan (PSP) Core Portfolio to reflect the availability and location of cost-effective resources (*i.e.*, "long-lead-time resources" that can fulfill the CPUC's Mid-term Reliability (MTR) requirements), including geothermal resources, in Nevada.
>
> The 20-Year Outlook includes roughly 2 gigawatts (GW) of geothermal from IID, but only 320 megawatts (MW) of geothermal in southern Nevada. The busbar mapping in the Decision Adopting the 2021 Preferred System Plan[3] increases the amount of geothermal in southern Nevada to 440 MW. At a minimum, the CAISO should reflect this increase in their 2022-2023 TPP and in the next iteration of the 20-Year Transmission Outlook. However, given the timeframe of the 20-Year Transmission Outlook, the CAISO should include the full potential for growth in Nevada geothermal that far exceeds 440 MWs. CalCCA requested the CPUC update the PSP to plan for at least 2,000 MW of further incremental renewable resources imported from Nevada. The CAISO should study the full 2,000 MWs requested by CalCCA in its comments to the PSP in the 2022-2023 TPP cycle and the next iteration of the 20-year Transmission Outlook allow the CAISO to evaluate necessary import expansion or transmission upgrades needed to deliver Nevada geothermal resources to California.
>
> Given the significant resource development opportunities out of state, the CAISO should also provide additional transparency on how transmission upgrades identified in the TPP will affect maximum import capability (MIC) needed for load-serving entities (LSEs) to show resources out of state as resource adequacy

(RA). LSEs must secure MIC at the right nodes to be able to use out-of-state resources like Nevada geothermal to provide RA capacity. Understanding how the TPP and 20-year plan will affect import capability at specific nodes would significantly improve LSEs' ability to make decisions around contracting and arranging transmission for potential projects to serve California load as RA. This transparency will minimize the risk of planned projects failing to materialize and minimize costs associated with the uncertainty around available MIC.

---

[1] *California Community Choice Association Reply Comments on the Proposed Decision Adopting 2021 Preferred System Plan*, Jan 19, 2022 (Rulemaking (R.) 20-05-003): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M443/K010/443010067.PDF.

[2] *Proposed Decision Adopting 2021 Preferred System Plan*, Dec 22, 2021 (R.20-05-003): https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=434547053.

[3] *Decision Adopting 2021 Preferred System Plan*, Attachment A Modeling Assumptions 2022-2023 TPP, Feb 10, 2022 (R.20-05-003): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K485/451485713.PDF.

6. Comment on chapter 5 High-Level Assessment:

CalCCA has no additional comments at this time.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
INFORMAL COMMENTS ON THE
LOCAL CAPACITY REQUIREMENT WORKING GROUP
February 2, 2022

I. INTRODUCTION

The California Community Choice Association[1] (CalCCA) appreciates the opportunity to comment on the Local Capacity Requirement (LCR) Working Group held on February 2, 2022. The CAISO Presentation[2] provided helpful clarity regarding the drivers of the 2021 and 2022 increases in Greater Bay Area requirements, interactions between the LCR and Transmission Planning Process (TPP), and how the LCR considers energy storage charging needs. In these comments, CalCCA recommends considerations that must be made in the Integrated Resource Planning (IRP) process and TPP when evaluating resource build and transmission upgrades needed to meet state policy goals at the lowest cost.

II. COMMENTS

When discussing the significant Greater Bay Area LCR changes for 2021 and 2022, the California Independent System Operator (CAISO) identified two drivers. First, the LCR reliability criteria changed in 2021. Second, the San Jose area experienced load growth for 2022 that required the use of more resources that are less-effective at meeting the constraints in other parts of the Bay Area. While the load forecast only increased by roughly 120 megawatts (MW),

---

[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] *California ISO Local Capacity Requirement (LCR) Working Group Meeting per CPUC's D.21-06-029*, Feb 2, 2022 (CAISO Presentation).

the resulting LCR increase was roughly 880 MW. The LCR increase was larger than the load forecast increase because the next set of resources that meet the contingency is very ineffective. The effectiveness factor of San Jose resources is roughly 30 percent, while the effectiveness factor of previously unused resources that are now needed to meet the new LCR is roughly 4 percent.[3] The result is procurement to meet a larger requirement relative to the increase in the forecast because each newly needed resource is so ineffective.

When changes to the local area such as load forecast increases result in large increases in LCR, several questions must be answered to most cost-effectively meet the new LCR. These include:

1. If the current resources have significantly low effectiveness factors, where should new resources locate to be more effective?
2. What are the transmission alternatives and how much do they cost compared to the large increase in local Resource Adequacy (RA) requirement or a new resource at a more effective location?
3. What information can be provided to the market about where new resources are needed based upon local area contingencies that are highly complex?

These questions should be answered through coordinated efforts between the California Public Utilities Commission (Commission) and the CAISO in the IRP and TPP. As the state progresses to meet state policy goals, it will become increasingly important to consider these questions. Achieving a zero-carbon electric system by 2045 will necessitate more renewable resource and storage development, creating opportunities for existing fossil fuel plants to retire. However, if an existing fossil fuel plant is in a locally constrained area, the resource retirement will not occur until the transmission constraint is eliminated or enough carbon-free resources are

---

[3] CAISO Presentation at 21.

built in the local area to fulfill the local need. The ability for local area resources to retire will also depend on the effectiveness factors of resources that would replace them. To avoid delays in meeting environmental standards, coordinated efforts between the Commission and the CAISO must occur to inform where new resources should locate to be highly effective at meeting the local need or, alternatively, where new transmission upgrades are needed to alleviate the local need.

IV. CONCLUSION

CalCCA appreciates the opportunity to comment on the LCR Working Group and urges the Commission and the CAISO to consider the recommendations herein.

Date: February 24, 2022

(*Original signed by*)

Eric Little
Director of Regulatory Affairs
California Community Choice Association
(510) 906-0182 | eric@cal-cca.org

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.21-10-002

CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) LOCAL CAPACITY REQUIREMENT (LCR) FINAL WORKING GROUP REPORT

Evelyn Kahl
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94520
Telephone: (415) 254-5454
E-Mail: regulatory@cal-cca.org

NOELLE R. FORMOSA
Attorney for
PACIFIC GAS AND ELECTRIC COMPANY
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-4655
Facsimile: (415) 973-5520
E-Mail: Noelle.Formosa@pge.com

February 28, 2022

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.21-10-002

CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) LOCAL CAPACITY REQUIREMENT (LCR) FINAL WORKING GROUP REPORT

Pursuant to the schedule set forth in (i) Ordering Paragraph ("OP") 5 of Decision ("D.") 21-06-029 and (ii) the December 2, 2021 Assigned Commissioner's Scoping Memo and Ruling and in accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the California Community Choice Association[1] ("CalCCA"), on behalf of itself and Pacific Gas and Electric Company ("PG&E") (together, the "Co-Leads"), respectfully submit the Local Capacity Requirement ("LCR") Final Working Group Report,[2] attached hereto as Attachment 1 ("Report"), that provides recommendations on (a) potential modifications to the current LCR timeline or processes to allow for more meaningful vetting of the LCR study results; (b) inclusion of energy storage limits in the LCR report and its

[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] Pursuant to Rule 1.8(d) of the Commission's Rules of Practice and Procedure, counsel for CalCCA certifies that PG&E has authorized CalCCA to sign and tender this document and to make the representations stated in Rule 1.8(b) on PG&E's behalf.

implications for future resource procurement; and (c) how best to harmonize the Commission's and the California Independent System Operator Corporation's local resource accounting rules, as required in OP 5 of D.21-06-029.[3] The Report also includes a discussion of the LCR's interaction with the Transmission Planning Process.

The Report includes the following appendices documenting the formal working group process:

Appendix A: Working Group Presentation

Appendix B: February 24, 2022 Informal Comments on the draft Local Capacity Requirement (LCR) Working Group Report.

The California Community Choice Association and Pacific Gas and Electric Company appreciate the opportunity to submit this Report.

Respectfully submitted,

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

February 28, 2022

---

[3] D.21-06-029, OP 5, at 75-76.

ATTACHMENT 1

CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) LOCAL CAPACITY REQUIREMENT (LCR) FINAL WORKING GROUP REPORT

FINAL WORKING GROUP REPORT

TABLE OF CONTENTS

I. INTRODUCTION

California's energy landscape, including its energy infrastructure, its regulatory structures, and its markets, have undergone, and continue to undergo, rapid and transformative change. In recent years local resource adequacy ("RA") requirements have increased significantly in response to increased load and adjusted reliability methodologies, specifically in the Greater Bay Area. These changes motivated the California Public Utilities Commission ("Commission") to convene a working group process in order to explore potential modifications to the local capacity requirement ("LCR") process.

A working group process workshop, held on February 2, 2022, provided significant clarity on LCR process and methodological adjustments. While this additional information will help stakeholders more effectively engage with the LCR process, arriving at and implementing solutions will require significant additional work. Stakeholders must acknowledge and leverage the crossover between the LCR process and parallel planning processes, especially with the Integrated Resource Planning ("IRP") process and Transmission Planning Process ("TPP"). Moreover, the Commission and the CAISO should coordinate to ensure that parties are sufficiently informed of LCR milestones through notification to the Commission's service lists. Finally, all parties must carefully consider the relationship between the local RA construct and state policy efforts and ensure that changes and adjustments sufficiently prioritize and balance those goals.

II. BACKGROUND AND PURPOSE OF THE LCR WORKING GROUP

In Decision ("D.") 20-06-031, the Commission and multiple stakeholders expressed concern on the significant increase in the local RA requirements within the Greater Bay Area. Specifically, the local RA requirements increased by approximately 1,800 megawatts ("MW") from 4,550 MW to 6,353 MW based on the California Independent System Operator Corporation's ("CAISO") Local Capacity Technical Study as completed in 2019 and 2020, respectively.

In completing its 2020 Local Capacity Technical Study, CAISO indicated that the increased local RA requirements within the Greater Bay Area were largely attributed to the updated local capacity technical study criteria (outlined in section III.A.3 below) used to establish the local procurement obligations, which changed from prior years. While CAISO has stated that the updated local capacity technical study criteria are intended to align with current mandatory reliability standards developed by the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council ("WECC"), the Commission had not directly considered the updated local capacity technical study criteria in its RA proceeding at that time (Rulemaking ("R.") 19-11-009). The

Commission therefore directed the establishment of a working group process to evaluate CAISO's updated local reliability criteria and other LCR-related issues. The LCR working group process would result in a Working Group Report and provide stakeholder recommendations on improving the local RA requirements process. Due to numerous issues in Track 3B and Track 4 of R.19-11-009, an Administrative Law Judge ruling was issued on February 2, 2021 that suspended the deadline for a Working Group Report on LCR recommendations.

In D.21-06-029, the Commission acknowledged that the working group process had made little progress on LCR-related issues and identified the California Community Choice Association ("CalCCA") and Pacific Gas and Electric Company ("PG&E") as the co-leads, going forward, of the working group process to bring to resolution some of the issues identified in R.19-11-009, including the increase in the Greater Bay Area local RA requirements. The Commission, however, narrowed the original scope, as outlined in D.20-06-031, and directed the working group process to evaluate the following narrower list of topics and submit a Working Group Report into the RA proceeding in February 2022:

a) Potential modifications to the current LCR timeline or processes to allow more meaningful vetting of the LCR study results;

b) Inclusion of energy storage limits in the LCR report and its implications on future resource procurement; and

c) How best to harmonize the Commission's and CAISO's local resource accounting rules.

A. Schedule of Completed Activities

The co-leads scheduled and completed the following working group process activities:

Date	Activity	Status
February 2, 2022	Co-leads facilitated a workshop to discuss the of topics identified in D.21-06-029.	Complete
February 18, 2022	Co-leads circulated a draft of the Working Gro Report.	Complete
February 24, 2022	Parties submitted informal comments in respor to the Working Group Report, including any recommendations for consideration by the Commission.	Complete
February 28, 2022	Co-leads filed and served the Working Group Report.	Complete

III. WORKSHOP DISCUSSION

A. Overview of the Purpose of the LCR and Reliability Criteria

1. Process and Timeline for Stakeholder Engagement

To begin the workshop, CAISO outlined the overall process and timeline for stakeholder engagement in the LCR process. The LCR stakeholder process for year n generally begins in the fall of year n-2 and ends in the spring of year n-1. For example, the local RA requirements for 2023 will begin in fall 2021 and will end in spring 2022. The LCR stakeholder process is a public forum that is open to all market participants and includes comment submission periods and meetings where stakeholders can be engaged with CAISO. CAISO has indicated that all comments related to the LCR study and its results should be directed through the CAISO LCR stakeholder process. This is the forum to provide the most impact to the stakeholder process. The final LCR study is then submitted into the Commission's RA proceeding each spring to be ultimately adopted as part of the Commission's local RA program. Below is a general timeline of key activities in the LCR stakeholder process.

General Timing	Activity for Study Year N
October (Year N-2)	CAISO stakeholders call to initiate the process
November (Year N-2)	Comments on methodology, criteria, and assumptions for study year
November/December (Ye N-2)	Base case development begins
January (Year N-1)	CAISO receives base case from participating transmission owner (PT
Mid-January (Year N-1)	CAISO publishes base case and stakeholders comment period
February (Year N-1)	Draft study completed
March (Year N-1)	CAISO stakeholders call on draft study and stakeholders comment pe
April (Year N-1)	CAISO stakeholders call on final study and stakeholders comment pe

2. Cross-Over with Transmission Planning Process

Next, the CAISO explained how LCR needs are addressed in the TPP. The CAISO explained that TPP projects can be authorized to reduce or eliminate LCR needs on a reliability, economic, or policy-driven basis. Reliability-driven mitigations are needed when an LCR area or sub-area is deficient in the number of resources to meet the LCR requirement. Economic-driven mitigations are used to reduce the LCR need for capacity or energy cost savings. Capacity cost savings are identified by using the price differential between the cost of the local capacity and the cost of system-wide capacity using the latest Commission RA Report. Energy cost savings are derived through production cost simulations. Policy-driven mitigations are dictated by state and federal policy goals. Renewable targets and battery procurement is used in the LCR study for the appropriate study year if exact locations are known. If the exact location is not known, guidance is given in the LCR report at the local and sub-area level. The LCR study also considers gas retirements, which the CAISO indicated are not binding in the next ten years and known upcoming retirements are included in the LCR study for the appropriate study year.

During the question-and-answer period, CalCCA expressed concern that as the state progresses to meet state policy goals, it will become increasingly difficult to plan for meeting local area reliability needs either through transmission upgrades to alleviate local areas or new resource build within local areas. CalCCA recommended that within the TPP process, the Commission and CAISO need to consider how the Transmission Plan and IRP process work together at the lowest cost.

CalCCA also asked the CAISO if the issue of local constraints and gas retirements needed to meet policy goals had been discussed in the TPP. The CAISO responded that it has looked at gas retirements for all LCR local areas and sub-areas within the last couple of years and directed parties to Appendix G for the 2018-2019 TPP[1], Appendix G for the 2019-2020 TPP[2] and Appendix G for the 2020-2021 TPP[3] that identifies transmission projects required to alleviate local constraints that allow for future gas retirements. The CAISO indicated that parties are expected to use the TPP (including the LCR studies) to identify resources that need to be procured in order to allow for resource retirements in local areas.

3. Factors Influencing Increases in the Bay Area Local Capacity Requirement

In D.21-06-029, the Commission identified significant additional increases to the Greater Bay Area local RA requirements as a primary driver for continuation of the working group process. The increases in question, of approximately 1,800 MW for 2021 and 900 MW for 2022, caused stakeholders to raise concerns regarding the CAISO's revised local capacity study criteria. Consequently, the CAISO's LCR methodology and criteria were centered as crucial discussion topics for the workshop. The CAISO presented extensively on the topic, providing significant clarity on process, opportunities for stakeholder engagement, and methodology.

Two factors were highlighted as primary causes for the Greater Bay Area local RA requirements increase: (1) a change in the LCR criteria that included the need to fully mitigate

---

[1] Appendix G – Board approved 2018-2019 Transmission Plan, March 29, 2019: http://www.caiso.com/Documents/AppendixG-BoardApproved2018-2019TransmissionPlan.pdf

[2] Appendix G – Board approved 2019-2020 Transmission Plan, March 26, 2020: http://www.caiso.com/Documents/AppendixG-BoardApproved2019-2020TransmissionPlan.pdf

[3] Appendix G – Board approved 2020-2021 Transmission Plan, March 26, 2021: http://www.caiso.com/Documents/AppendixG-BoardApproved2020-2021TransmissionPlan.pdf

transformer outages, and (2) an increase in load in the San Jose area. The updated CAISO LCR criteria now reflects mandatory NERC standards requiring transformer failures to be mitigated by either local resource procurement or be rectified by PG&E as the participating transmission owner through new transformer ratings or be rectified through new transmission project(s) approved by the CAISO in the TPP. To date, CAISO is not aware of increases to the transformer ratings or proposed transmission upgrade to mitigate the issue. Consequently, additional local RA resources are required to account for transformer-related contingencies – which were previously mitigated by the same resources in the area without specifically imposing local requirements, due to the previous mismatch between the two criteria. Correspondingly, an approximately 120 MW increase in load in the San Jose area requires utilizing less “effective” resources from Pittsburg and Contra Costa County, since all of the most “effective” resources in the San Jose area were already used in the previous year. Crucially, the minimum effective LCR is achieved by utilizing the most “effective” available resources first. The already-used resources present in the San Jose area have an approximate CAISO local effectiveness factor of 30 percent, while previously unused resources have a CAISO local effectiveness factor of only about 4 percent.

a. Change to Mandatory NERC Standards and Impact

CAISO indicated that it conducted a stakeholder process in 2019 to update the LCR criteria to align with current mandatory reliability standards developed by NERC, WECC, and CAISO. Following this open stakeholder process, the Federal Energy Regulatory Commission (“FERC”) approved CAISO tariff changes to align the LCR criteria with mandatory standards on January 17, 2020, with no stakeholder opposition. The CAISO Board and FERC approved updates to the LCR criteria as outlined in CAISO Tariff Section 40.3.1.1 and contingencies as identified in CAISO Tariff Section 40.3.1.2. In particular, CAISO:

a) Updated category definitions to align with current NERC standards.

b) Updated bulk electric system (BES) voltage level definitions and aligned application of non-BES criteria accordingly.

c) Fully aligned LCR criteria for BES with more stringent NERC, WECC, and CAISO mandatory standards.

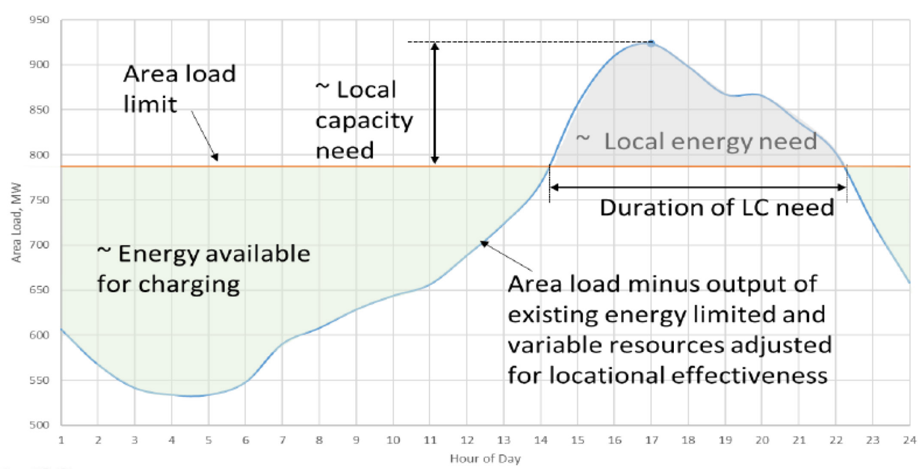
With regards to CAISO fully aligning LCR criteria for BES with more stringent mandatory NERC standards, CAISO stated that alignment of these standards provides greater transparency to the RA program and aligns LCR study criteria with the standards used in transmission development and for reliability must-run contracts. These changes update the category definitions, update the BES voltage level definition and application of non-BES criteria, and partially relaxes an old local capacity requirement.

B. Overview of Energy Storage Analysis and Implications to Procurement Decisions

The CAISO next presented how the LCR study process considers the need to sufficiently charge storage in locally constrained areas. The CAISO indicated that within the LCR study, local storage resources must be able to charge from the grid during all extended outage conditions by using either remaining transmission capacity into the constrained area or other contracted resources inside the constrained area. In response to a question from CalCCA, the CAISO clarified that when considering generation resources available to charge storage, the CAISO includes the number of resources needed to meet the LCR requirement (i.e., the amount of local RA that will be available).

The CAISO developed a methodology for assessing the local energy requirement and the charging feasibility of storage resources. The methodology compares the hourly forecasted net load on a peak day against the area load limit.

Figure 1: Methodology for Assessing Local Energy Need and Charging Feasibility[4]



The assessment includes an hour-by-hour comparison of the net-load versus the total load-serving capability. Total local load-serving capability includes:

- Transmission load-serving capability calculated under the worst contingency condition without any local generation; and,
- Local generation load-serving capability calculated under the worst contingency condition with the amount of generation needed according to the local capacity requirement considering the effectiveness of the aggregate of local generation to the worst constraint.

[4] CAISO Presentation at 29.

The CAISO explained that it uses the following assumptions in the energy storage assessment:

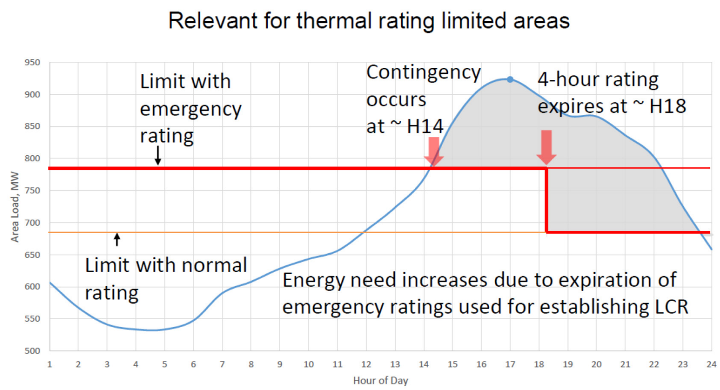
Table 1: Key Assumptions used in Energy Storage Assessment

Assumption	Rationale
Storage added displaces existing generatio (all types) MW for MW in aggregation.	To maintain local RA capacity. Any incremental storage is assumed to be a loc RA resource.
Maximum storage addition cannot exceed LCR amount.	To maintain local RA capacity. Any incremental storage is assumed to be a loc RA resource.
Includes storage charging/discharging efficiency of 85%.	Based on general battery efficiency.
Storage is charged in all hours where the storage is not discharged. Maximum charg is capped at the amount of storage size (Pmin).	Under worst contingency condition, for battery to have sufficient discharge energy is assumed that battery is charged in all ho it is not discharged.
An hourly energy margin of 5% or 10 MW the larger of the two, is applied to both charging and discharging need.	To add margin when battery is dischargin it does not have to follow load curve exac For charging same margin is added to discount available system capability each hour.

The CAISO noted that most load serving entities procure 4-hour batteries due to current Commission system RA counting rules. Because of this, the CAISO now includes in the LCR study a maximum MW quantity of 4-hour batteries that can provide a 1-for-1 replacement of resources needed in that local area or sub-area. The CAISO explained that beyond this limit, batteries may not reduce the need for other local resources on a 1-for-1 basis. In response to a question from PG&E, the CAISO clarified that the maximum MW quantity of 4-hour 1-for-1 replacement is the limit for the amount of 4-hour duration resources that can be used. Longer duration resources could be used beyond that limit.

The CAISO concluded by discussing potential future enhancements it is considering to better account for storage in the LCR. This enhancement would include the differences between normal and emergency line ratings when assessing energy needs in local areas. Currently, the CAISO only uses the emergency rating.

Figure 2: Potential Future Enhancements - Effect of the Difference Between Normal and Emergency Ratings[5]



During the question-and-answer period, Calpine Corporation asked if the storage charging assessment focuses on the peak day, if there was a chance the assessment would miss other reliability challenges. For example, if the other resources in the local area are solar, there may not be enough energy to charge in winter when storage is not available rather than on the peak day. The CAISO indicated it is beginning to focus on these potential challenges more, as these circumstances may become more prevalent in the future. The California Energy Storage Alliance ("CESA") asked why the CAISO does not consider multi-day contingency events in its assessment. The CAISO responded that the assessment focuses on ensuring the peak day requirement is met and it is implied that if the batteries can charge under the worst peak day condition they could also charge in any other subsequent day, with less load, on a multi-day contingency event.

IV. RECOMMENDATIONS

On February 18, 2022, CalCCA and PG&E circulated a draft of the Working Group Report and requested that parties submit informal comments in response to the Working Group Report, including any recommendations for consideration by the Commission. Parties were requested to submit informal comments on February 24, 2022.

On February 24, 2022, no parties provided further edits to the report. CalCCA, the CAISO, Middle River Power, LLC, and San Diego Gas & Electric Company all submitted informal comments to the working group. Those informal comments have been attached as Appendix B to this Working Group Report.

---

5 CAISO Presentation at 33.

APPENDIX A
TO ATTACHMENT 1

CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) LOCAL CAPACITY REQUIREMENT (LCR) FINAL WORKING GROUP REPORT

CALIFORNIA ISO
LOCAL CAPACITY REQUIREMENTS (LCR)
WORKING GROUP MEETING PER CPUC'S D.21-06-029

Local Capacity Requirements (LCR) Working Group Meeting per CPUC's D.21-06-029

Catalin Micsa

Senior Advisor Regional Transmission Engineer

Working Group Call

February 2, 2022

Agenda

1. Introduction
2. References of current standards
3. Recap: full alignment of LCT criteria with mandatory criteria
4. 2021 - overall LCR study results and Bay Area increase
5. 2022 - secondary Bay Area increase
6. LCR needs and the TPP process
7. RA counting and its link to the LCR study and ISO back-stop
8. Charging for storage used as local RA resources
9. Open discussion

Introduction

- Resource Adequacy (RA)
  - Ensure that capacity exists and is under contract in order for all load to be served by responsible Load Serving Entities (LSEs)
  - Generally, LSEs will demonstrate that they have secured adequate qualified capacity to serve their peak load including planning reserve (every month in the month ahead timeframe).
  - Generally, LSEs will demonstrate, in the year ahead timeframe that they have secured 100% of local resources and minimum 90% of the next summer's peak load needs including planning reserve.
  - All resources participating in the ISO markets under an RA contract will have an RA must-offer-obligation to the ISO.

Introduction (cont.)

- The Local Capacity Requirements (LCR) have been introduced in the Resource Adequacy (RA) program in order to allow Load Serving Entities (LSEs) to directly contract with local resources required to meet local reliability by effectively replacing ISO Local Area Reliability Service (LARS) process.
- The LCR process is a yearly process with yearly requirements (not seasonally, monthly, daily or hourly)
- Per ISO Tariff
  - ISO can determine minimum local resource requirements and allocate them to LSEs in order to maintain reliability standards
  - If LSE procurement falls short of ISO's identified needs then ISO may engage in backstop procurement role to assure reliability standards are met in local areas

Introduction (cont.)

- The local capacity study stakeholder process is conducted at the ISO annually, starting in the fall of one year and ending in the spring of the next
  - *E.g.*, the 2023 local capacity study started in fall 2021 and will complete in spring 2022
  - 2023 stakeholder process available at: https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Local-capacity-requirements-process-2023
- The stakeholder process is open to all, includes comment submission periods and meetings where stakeholders can ask questions.
- All comments related to the LCR process and its results should be directed to the ISO LCR process.
- The final LCR needs are filed into the CPUC's RA proceeding each spring.

Introduction (cont.)

CPUC and the ISO have determined overall timeline:

- ISO stakeholder call Oct. 27, 2021 - Methodology, criteria and assumptions - comments by November 10, 2021
- Base case development will start in November-December 2021
- Receive base cases from PTOs January 4, 2022
- Publish base cases January 14, 2022 – comments by the 28th
- Draft study completed by February 25, 2022
- ISO Stakeholder meeting March 9, 2022 – Draft study results - comments by March 23, 2022
- ISO receives new operating procedures March 23, 2022
- Validate op. proc. – publish draft final report April 1, 2022
- ISO Stakeholder call April 12, 2022 – Final study results - comments by April 22, 2022
- Final report April 29, 2022 (May 1st for most years)

Introduction (cont.)

- Per ISO Tariff, the ISO allocates the total local capacity requirements by TAC to all LSEs with load in that TAC based on their load share ratio within that TAC at the time of the ISO peak.
- Per ISO Tariff, the CPUC, as the only Local Regulatory Agency (LRA) with multiple LSEs can split its appropriate share of the LCR needs among its jurisdictional LSEs. If the CPUC does not split the entire amount the ISO must allocate the remaining need based on ISO methodology to all the CPUC jurisdictional LSEs.

References of current standards:

NERC TPL-001-4:

https://www.nerc.com/files/TPL-001-4.pdf

WECC TPL-001-WECC-CRT-3.1:

https://www.wecc.org/Reliability/TPL-001-WECC-CRT-3.1.pdf

ISO Planning Standards:

http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf

Previous Local Capacity Technical Study Criteria

- Initially developed through the LCT Study Advisory Group (“LSAG”); an advisory group formed by the CAISO to assist the CAISO in its preparation for performing LCT Studies prior to the start of the Resource Adequacy program.

- Old LCT study criteria was established before North America Electric Reliability Corporation (NERC) required mandatory standards were formed and it represented a subset of the NERC voluntary standards available at the time.

ISO Board Approved in November 2019

- Following an open stakeholder process that included three stakeholder engagements and three rounds of comments
- And based on overwhelming stakeholder support
- The ISO Board and FERC have approved updates the Local Capacity Technical (LCT) study
  - Criteria as set out in ISO Tariff section 40.3.1.1; and
  - Contingencies as identified in ISO Tariff section 40.3.1.2.

Updates to category definitions needed to align with current NERC standards.

- Currently, the NERC TPL-001-4 standard characterizes contingencies from P0 to P7 plus extreme contingencies.
- Previous standards categorized them from A to D – fewer and less comprehensive categories.
- ISO replaced the old references with new references and characterization

Stakeholder feedback:

- General agreement

Update bulk electric system (BES) voltage level definition and align application of non-BES criteria accordingly.

- NERC BES definition has changed in recent years and now generally includes:
  - Extra High Voltage (> 300 kV) and
  - High Voltage (generally > 100 kV and < 300 kV).
- Generally, elements < 100 kV are not considered BES and are planned to meet ISO Planning standards
- For non-BES facilities, the ISO Planning Standards will be used LCT studies as well as planning studies.

Stakeholder feedback:

- General agreement

Partially relaxing an old local capacity requirement:

- Old LCT study criteria required mitigating all N-1 followed by L-2 contingencies that could cause voltage collapse or dynamic instability
- Mandatory standards only require that this “extreme event” be studied and mitigations considered based on the planners’ assessment of risk and consequences.
- Criteria modified to only require mitigation “if there is a risk of cascading” beyond a relatively small predetermined area, not to exceed 250 MW, directly affected by the outage.

Stakeholder feedback:

- General support

Fully align LCT study criteria for BES with more stringent NERC, WECC, ISO mandatory standards:

- Provides greater transparency of all reliability needs to the resource adequacy program.
- Full criteria is already used in new transmission development and to retain existing resources under reliability must-run contracts.

Stakeholder feedback:

- Strong support

Why full alignment?

- Provides level playing field for build-up of transmission and/or new RA resources.
- Provides level playing field for build-up of new RA resources vs. old in need of retirement resources.
- Provides decision makers better tools to prepare for long-term overall system planning.
- The Reliability Must Run (RMR) need for an old resources asking for retirement/mothball is evaluated against entire mandatory criteria.
- Load shedding is a viable mitigation, where allowed by NERC standards. New or upgrades to Special Protection Schemes/Remedial Action Schemes (SPS/RAS) can be used and must comply with ISO Grid Planning standards.

Difference between mandatory standards vs. LCT criteria

Contingency Component(s)	Mandatory Reliability Standards	Old Local Capacity Criteria	Current Local Capacity Criteria
P0 – No Contingencies	X	X	X
P1 – Single Contingency			
1. Generator (G-1)	X	X[1]	X[1]
2. Transmission Circuit (L-1)	X	X[1]	X[1]
3. Transformer (T-1)	X	X[1,2]	X[1]
4. Shunt Device	X		X
5. Single Pole (dc) Line	X	X[1]	X[1]
P2 – Single contingency			
1. Opening a line section w/o a fault	X		X
2. Bus Section fault	X		X
3. Internal Breaker fault (non-Bus-tie Breaker)	X		X
4. Internal Breaker fault (Bus-tie Breaker)	X		X
P3 – Multiple Contingency – G-1 + system adjustment and:			
1. Generator (G-1)	X	X	X
2. Transmission Circuit (L-1)	X	X	X
3. Transformer (T-1)	X	X[2]	X
4. Shunt Device	X		X
5. Single Pole (dc) Line	X	X	X

Difference between mandatory standards vs. LCT criteria

Contingency Component(s)	Mandatory Reliability Standards	Old Local Capacity Criteria	Current Local Capacity Criteria
P4 – Multiple Contingency - Fault plus stuck breaker			
1. Generator (G-1)	X		X
2. Transmission Circuit (L-1)	X		X
3. Transformer (T-1)	X		X
4. Shunt Device	X		X
5. Bus section	X		X
6. Bus-tie breaker	X		X
P5 – Multiple Contingency – Relay failure (delayed clearing)			
1. Generator (G-1)	X		X
2. Transmission Circuit (L-1)	X		X
3. Transformer (T-1)	X		X
4. Shunt Device	X		X
5. Bus section	X		X
P6 – Multiple Contingency – P1.2-P1.5 system adjustment and:			
1. Transmission Circuit (L-1)	X	x	X
2. Transformer (T-1)	X	x	X
3. Shunt Device	X		X
4. Bus section	X		X

Difference between mandatory standards vs. LCT criteria

Contingency Component(s)	Mandatory Reliability Standards	Old Local Capacity Criteria	Current Local Capacity Criteria
<u>P7 – Multiple Contingency - Fault plus stuck breaker</u>			
1. Two circuits on common structure (L-2)	X	X	X
2. Bipolar DC line	X	X	X
<u>Extreme event – loss of two or more elements</u>			
Two generators (Common Mode) G-2	X[4]	X	X[4]
Any P1.1-P1.3 & P1.5 system readjusted (Common Mode) L-2	X[4]	X[3]	X[5]
All other extreme combinations.	X[4]		X[4]

[1] System must be able to readjust to a safe operating zone in order to be able to support the loss of the next contingency.

[2] A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

[3] Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.

[4] Evaluate for risks and consequence, per NERC standards.

[5] For voltage collapse or dynamic instability situations mitigation is required "if there is a risk of cascading" beyond a relatively small predetermined area directly affected by the outage.

Major Changes from year 2020 to year 2021

1. Total 2021 LCR capacity needed has increased by 517 MW or ~ 2.2%.
2. 2021 LCR needs decrease in: Big Creek/Ventura and San Diego due to load forecast decrease, LA Basin due to new transmission projects, Stockton due to changes in the LCR criteria, Kern due to decrease in available Qualifying Capacity, Fresno and Humboldt requirement is the same.
3. 2021 LCR needs increase in: North Coast/North Bay due to change in the LCR criteria, Bay Area and Sierra due to load forecast increase and change in the LCR criteria.
4. Mixed bag some areas and sub-areas LCR needs went up some went down with many sub-areas being eliminated.

Biggest increase - Greater Bay Area Overall

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2020	B	Reactive margin	Tesla-Metcalf 500 kV line & DEC unit	3970
	C	Aggregate of subareas		4550

Year	Category	Limiting Facility	Contingency	LCR (MW)
2021	P6	Metcalf 500/230 kV #13 transformer	Metcalf 500/230 kV #11 & #12 transformers	6353

Compared to 2020 the 2021 load forecast went up by 292 MW and total LCR need went up by 1803 MW mainly due to LCR criteria change.

Secondary increase - Greater Bay Area Overall

Year	Category	Limiting Facility	Contingency	LCR (MW)
2022	P6	Metcalf 500/230 kV #13 transformer	Metcalf 500/230 kV #11 & #12 transformers	7231

Compared to 2021 load forecast went down by 34 MW and total LCR need went up by 878 MW mainly due to load growth seen in the San Jose area (SVP) and it being very effective on the Metcalf 500/230 kV transformer banks. With all San Jose resources previously being used, the increased need had to be picked up by bigger amounts of less effective resources in other parts of the Bay Area.

- Min LCR is achieved by using the most effective units FIRST (see manual)
- San Jose resources and load effectiveness factor is ~30% (21-40%)
- Previously unused resources effectiveness factor is ~4% (3-6%)
- ~120 MW San Jose load increase = ~880 MW of LCR increase

LCR needs and the TPP process

- Reliability mitigation - any LCR area or sub-area that is “deficient” needs a reliability mitigation in the TPP process.
- Economic mitigation - reducing LCR needs has two components:
  1. Capacity cost saving - driven by the reduction in LCR needs and the differential in price between the cost of the local capacity vs the cost of system wide capacity (latest CPUC RA report is used for such costs).
  2. Energy cost savings - derived through production cost simulations.

LCR needs and the TPP process (cont.)

- Policy mitigation - dictated by state and federal policy goals.
  1. Renewable target - used in the appropriate study year (if exact location is known), else guidance is given in every LCR report at the local area and sub-area level.
  2. Battery procurement - used in the appropriate study year (if exact location is known), else guidance is given in every LCR report at the local area and sub-area level.
  3. Gas retirements - not binding in the next 10 years - results available in the 10 year out study included as Appendix G to the 2019-20 and the 2020-21 TPP write-up.
  4. Known upcoming retirements (OTC, nuclear, public data) - already included in the LCR study for the appropriate study year.

RA Counting or Qualifying Capacity

- Per previous FERC rulings and ISO Tariff section 40.8.1 the Local Regulatory Agencies (LRAs) like CPUC have the authority to set the Qualifying Capacity:
  - CAISO has default rules (in case LRAs don’t have their own rules)
- Per CPUC rulings and ISO Tariff, along with many technical reasons, each resource must have a single QC (NQC) value. It is NOT allowed to have one value for system and one value for local.
- The only reason a resource counts for local is because it is located inside a local area.
- ISO can decrease the QC to NQC, for testing (Pmax), performance criteria (not used) and deliverability.

The LCR Study

- DOES NOT establish RA counting
- DOES establish the local RA resources (by delimiting the local area boundaries)
- DOES establish the individual local RA requirement for each LSE based on their load share ratio within the TAC vs. the total LCR requirement for that TAC
- DOES establish the technical requirements.
  - Total MW need by TAC (RA individual enforcement + ISO back stop)
  - MW need by local area or sub-area (RA guidance only + ISO back stop)
  - Effectiveness factors (RA guidance only + ISO back stop)
  - Load charts (RA guidance only + ISO back stop)
  - Battery charging parameters (RA guidance only + ISO back stop)

ISO local CPM enforcement

- Total MW need by TAC + MW need by local area or sub-area + Effectiveness factors + Load charts + Battery charging limits
  - In the year ahead costs are first allocated to individual deficient LSEs on their month by month deficiency bases as available in their year ahead annual showing
  - Second remaining costs are allocated to all LSEs

- The technical requirements (justification for the local CPM) must be made public, therefore the need to include them in the LCR reports.

ISO RMR enforcement

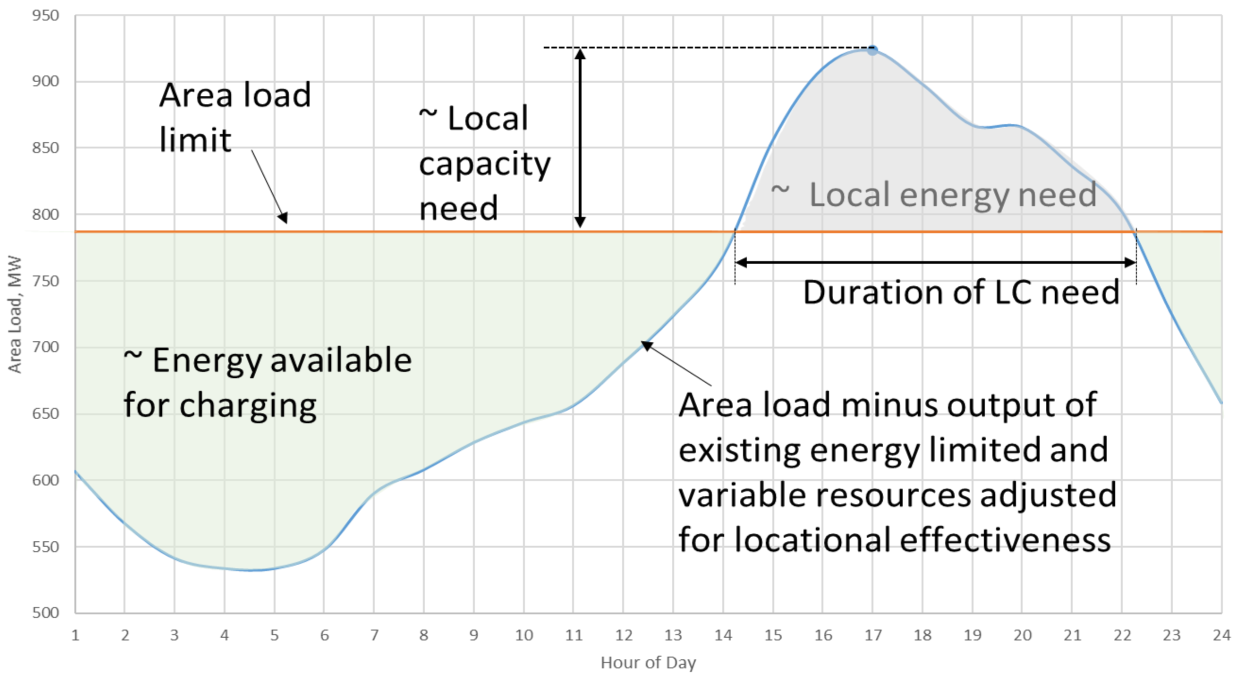
- RMR is not automatic – a resource must be non-RA and must ask (by submitting a signed affidavit) for retirement or mothball
- ISO can enforce any reliability need (Total MW need by TAC + MW need by local area or sub-area + Effectiveness factors + Load charts + Battery charging limits)
- Costs are divided to all the LSEs in the appropriate TAC(s) that drive the local need.
- The technical requirements (justification for these RMR contracts) must be made public, therefore the need to include them in public reports.

Charging for Storage used as local RA resources

- Local storage resources must be able to charge from the grid during all extended outage conditions (except extreme events) by using
  - Remaining transmission capacity into the constrained area
  - Other contracted for resources inside the constrained area

Methodology for assessing local energy need and charging feasibility

- Due to the energy limitation and need for charging, the following the methodology has been developed for assessing energy requirement and charging feasibility.
- The methodology is based on comparing the forecast hourly area effective net load for peak day against the area load carrying capability limit (area load limit).



Energy Storage Assessment Approach – Load vs load serving capability

- The assessment includes an hour-by-hour comparison of the net load versus the total (transmission + generation) load serving capability.
- Peak day 24-hour load profile is used, either directly from the CEC hourly load forecast or future year load profile developed by escalating from the historical load profile for the study area.
- Total local load serving capability includes the transmission load serving capability and local generation load serving capability.
  - The transmission load serving capability is calculated under the worst contingency condition without any local generation.
  - The local generation load serving capability is calculated under the worst contingency condition with the amount of generation needed according to the local capacity requirement considering effectiveness of the aggregate of local generation to the worst constraint.

Key assumptions used in energy storage assessment

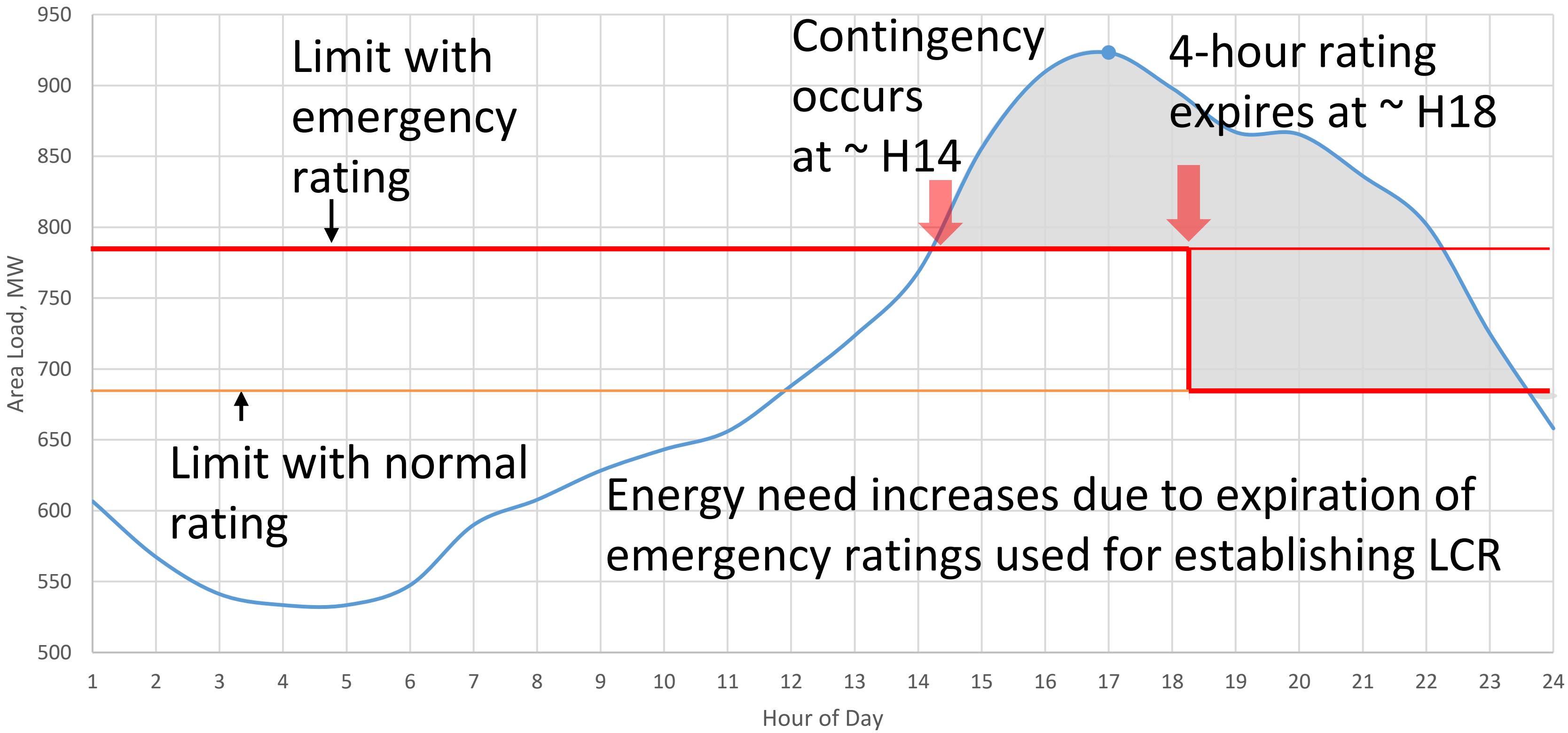
Assumption	Rationale
Storage added displaces existing generation (all types) MW for MW in aggregation.	To maintain local RA capacity. Any incremental storage is assumed to be a local RA resource.
Maximum storage addition cannot exceed LCR amount.	To maintain local RA capacity. Any incremental storage is assumed to be a local RA resource.
Includes storage charging/discharging efficiency of 85%.	Based on general battery efficiency.
Storage is charged in all hours where the storage is not discharged. Maximum charging is capped at the amount of storage size (Pmin).	Under worst contingency condition, for battery to have sufficient discharge energy, it is assumed that battery is charged in all hours it is not discharged.
An hourly energy margin of 5% or 10 MW, the larger of the two, is applied to both charging and discharging need.	To add margin when battery is discharging so it does not have to follow load curve exactly. For charging same margin is added to discount available system capability each hour.

Additional consideration in presenting storage capability as part of Local Capacity Requirement (LCR) study

- Majority of LSEs are procuring (4 MWh for every 1 MW) batteries (due to current CPUC rules for system RA counting)
- The ISO has introduced “Maximum MW quantity of (4 MWh for every 1 MW) battery as 1 for 1 replacement” of resources needed in that local area or sub-area
  - Beyond this limit batteries may not reduce the need for other local resource on a 1 for 1 bases.

Potential future enhancements: Effect of difference between normal and emergency ratings

Relevant for thermal rating limited areas



California ISO

Open discussion

APPENDIX B
TO ATTACHMENT 1

CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) LOCAL CAPACITY REQUIREMENT (LCR) FINAL WORKING GROUP REPORT

INFORMAL COMMENTS RECEIVED FEBRUARY 24, 2022:

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

MIDDLE RIVER POWER, LLC

SAN DIEGO GAS & ELECTRIC COMPANY

CALCCA
ADVANCING LOCAL ENERGY CHOICE

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
INFORMAL COMMENTS ON THE
LOCAL CAPACITY REQUIREMENT WORKING GROUP
February 2, 2022

I. INTRODUCTION

The California Community Choice Association[1] (CalCCA) appreciates the opportunity to comment on the Local Capacity Requirement (LCR) Working Group held on February 2, 2022. The CAISO Presentation[2] provided helpful clarity regarding the drivers of the 2021 and 2022 increases in Greater Bay Area requirements, interactions between the LCR and Transmission Planning Process (TPP), and how the LCR considers energy storage charging needs. In these comments, CalCCA recommends considerations that must be made in the Integrated Resource Planning (IRP) process and TPP when evaluating resource build and transmission upgrades needed to meet state policy goals at the lowest cost.

II. COMMENTS

When discussing the significant Greater Bay Area LCR changes for 2021 and 2022, the California Independent System Operator (CAISO) identified two drivers. First, the LCR reliability criteria changed in 2021. Second, the San Jose area experienced load growth for 2022 that required the use of more resources that are less-effective at meeting the constraints in other parts of the Bay Area. While the load forecast only increased by roughly 120 megawatts (MW),

---

[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] *California ISO Local Capacity Requirement (LCR) Working Group Meeting per CPUC's D.21-06-029*, Feb 2, 2022 (CAISO Presentation).

the resulting LCR increase was roughly 880 MW. The LCR increase was larger than the load forecast increase because the next set of resources that meet the contingency is very ineffective. The effectiveness factor of San Jose resources is roughly 30 percent, while the effectiveness factor of previously unused resources that are now needed to meet the new LCR is roughly 4 percent.[3] The result is procurement to meet a larger requirement relative to the increase in the forecast because each newly needed resource is so ineffective.

When changes to the local area such as load forecast increases result in large increases in LCR, several questions must be answered to most cost-effectively meet the new LCR. These include:

1. If the current resources have significantly low effectiveness factors, where should new resources locate to be more effective?
2. What are the transmission alternatives and how much do they cost compared to the large increase in local Resource Adequacy (RA) requirement or a new resource at a more effective location?
3. What information can be provided to the market about where new resources are needed based upon local area contingencies that are highly complex?

These questions should be answered through coordinated efforts between the California Public Utilities Commission (Commission) and the CAISO in the IRP and TPP. As the state progresses to meet state policy goals, it will become increasingly important to consider these questions. Achieving a zero-carbon electric system by 2045 will necessitate more renewable resource and storage development, creating opportunities for existing fossil fuel plants to retire. However, if an existing fossil fuel plant is in a locally constrained area, the resource retirement will not occur until the transmission constraint is eliminated or enough carbon-free resources are

---

3 CAISO Presentation at 21.

built in the local area to fulfill the local need. The ability for local area resources to retire will also depend on the effectiveness factors of resources that would replace them. To avoid delays in meeting environmental standards, coordinated efforts between the Commission and the CAISO must occur to inform where new resources should locate to be highly effective at meeting the local need or, alternatively, where new transmission upgrades are needed to alleviate the local need.

IV. CONCLUSION

CalCCA appreciates the opportunity to comment on the LCR Working Group and urges the Commission and the CAISO to consider the recommendations herein.

Date: February 24, 2022

(*Original signed by*)

Eric Little
Director of Regulatory Affairs
California Community Choice Association
(510) 906-0182 | eric@cal-cca.org

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations	Rulemaking 21-10-002 (Filed October 7, 2021

INFORMAL COMMENTS ON CALIFORNIA COMMUNITY CHOICE ASSOCIATION AND PACIFIC GAS AND ELECTRIC COMPANY LOCAL CAPACITY REQUIREMENT WORKING GROUP REPORT OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. Introduction

The California Independent System Operator Corporation (CAISO) submits informal comments in response to the Draft Working Group Report (Draft Report) by the California Community Choice Association (CalCCA) and Pacific Gas and Electric Company (PG&E). Decision (D.) 20-06-031 identified CalCCA and PG&E as the co-leads of a working group to evaluate three specific local capacity requirement (LCR) topics and to submit the working group report. The working group convened on February 2, 2022 and the co-leads distributed the Draft Report to the service list on February 18, 2022.

II. Discussion

The CAISO reviewed the Draft Report and has no further edits to the written report. The CAISO provides comments on each of the LCR topics below.

A. Topic 1: Potential Modifications to the Current LCR Timeline or Processes to Allow More Meaningful Vetting of the LCR Study Results

The CAISO has worked collaboratively with Commission Energy Division staff to ensure timely delivery of LCR study results. The CAISO relies on the California Energy Commission (CEC) for the underlying demand forecast to develop the LCR needs. Despite occasional delays in receiving the demand forecast, the CAISO has been able to deliver the LCR results to the Commission with sufficient time to establish Commission-jurisdictional LCR needs. Moreover, the CAISO typically meets Commission-established deadlines for providing the final LCR study, despite undertaking additional analysis, such as developing engineering-managed results when local capacity requirements changed from a one- to three-year forward assessment and performing the storage charging assessment discussed below.

The CAISO has a robust and transparent multiple month-long stakeholder process (as described in the Draft Report in Section III.A.1) that allows for meaningful vetting, discussion, and analysis. Stakeholders should appropriately participate in the CAISO stakeholder process for any questions regarding the LCR study criteria, methodology, and results.

To improve coordination, the CAISO can work with Commission Energy Division staff to ensure the start of the CAISO's stakeholder process is also noticed via the Commission's service list. However, the CAISO cannot continue to compress its own stakeholder process timelines.

B. Topic 2: Inclusion of energy storage limits in the LCR report and its implications on future resource procurement

As discussed in the Draft Report,[1] the CAISO provided energy storage limit information to help the Commission, load serving entities, and the Central Procurement Entities form a better understanding of their collective procurement impacts in each local capacity area and sub-area vis-à-vis the existing and projected storage buildout.

C. Topic 3: How Best to Harmonize the Commission's and CAISO's Local Resource Accounting Rules

As explained by the CAISO at the February 2nd workshop, existing CAISO and Commission rules require that a resource adequacy resource cannot receive, show, or otherwise sell a different net qualifying capacity (NQC) value towards meeting the local versus system requirement. In other words, a resource adequacy resource counts towards the local requirement because it is located in a given local area; however, the local counting value must be the same as that established by the Local Regulatory Agency (LRA) towards meeting the system-wide requirement. Therefore, in the CAISO systems all resources shown for local resource adequacy count both towards local resource adequacy and toward the system resource adequacy requirements based on their respective monthly NQC values as established by the LRA.

[1] Draft Report, pp. Attachment 1-10 to 1-13.

III. Conclusion

The CAISO appreciates the opportunity to comment on the Draft Report. To improve coordination, the CAISO can work with Commission Energy Division staff to ensure the start of the CAISO's stakeholder process is also noticed via the Commission's service list.

Date: February 24, 2022

Middle River Power LLC Informal Comments on California Community Choice and Pacific Gas and Electric Company (U 39 E) Local Capacity Requirement (LCR) Working Group Report

As directed in Shawn-Dai Linderman's February 18, 2022 e-mail to parties in rulemakings R.19-11-009 and R.21-10-002, Middle River Power LLC ("MRP") hereby submits its informal comments on the draft Local Capacity Requirement ("LCR") Working Group Report ("LCR WG Report").

MRP appreciates the narrower LCR Working Group Scope adopted in D.20-06-031 and included on page Attachment 1-4 of the report. This narrower scope focuses only on (1) the LCR timeline; (2) including energy storage limits in the LCR report; and (3) local resource counting rules. This narrower scope does not contemplate the Commission undertaking a process to develop LCR that differ from the LCR developed by the CAISO. The CAISO has established processes for developing the LCR and for considering changes to the criteria used in the LCR studies. Given the CAISO's obligation to operate the bulk power system under its operational control in accordance with approved North American Electric Reliability Council ("NERC"), Western Electricity Coordinating Council ("WECC") and California Independent System Operator ("CAISO") criteria, and its primary role in developing LCR, MRP strongly believes that the CAISO, not the Commission, should be establishing the LCR used in the Commission's and CAISO's Resource Adequacy ("RA") programs.

In the discussion on the CAISO's Energy Storage analysis on page Attachment 1-13, the report relates a California Energy Storage Alliance ("CESA") question about why the CAISO does not consider multi-day contingency events in its local energy storage assessment. The report describes CAISO as responding that its assessment ensures that the peak-day charging requirement can be met and, if the batteries can charge under the peak-day conditions, they could charge in any other day with less load. As MRP understands, the CAISO's response is true if the "worst day" is defined only in terms of local area load and transmission network topology, and the associated local charging resources are not weather- or fuel-dependent. If the local charging resources are weather- or fuel-dependent, a "worst-case" day could involve a confluence of load, network topology and weather/fuel inadequacy conditions.

MRP offers the following recommendations for the report:

- Energy Division staff should notice upcoming CAISO local capacity technical study methodology meetings to parties so that all parties have the opportunity to participate in the CAISO's stakeholder process to establish the LCR.

- The Commission should adopt the CAISO's LCR values without modifications.

    - If the Commission elects to adopt a different LCR value, then such values should also be based on engineering studies performed by either Energy Division or third parties and the Commission should provide a detailed explanation as to why it adopted a different number than the CAISO's number in the relevant proposed and final Commission decisions.

February 24, 2022

INFORMAL COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY REGARDING RESOURCE ADEQUACY (R.21-10-002), IMPLEMENTATION TRACK, PHASE 2 LOCAL CAPACITY REQUIREMENT

San Diego Gas & Electric Company (SDG&E) appreciates the opportunity to provide these comments regarding the draft Local Capacity Requirement (LCR) Working Group Report.

SDG&E generally supports the analysis performed by the California Independent System Operator (CAISO) regarding the integration of energy storage resources. As the resource portfolio grows to incorporate more battery resources, it will be important to accurately plan for the use-limited nature of these resources. CAISO's methodology for assessing charging feasibility is a good approach, as it includes an hourly assessment of whether resources can meet load in each LCR pocket. SDG&E suggests holistic consideration of the limitations of these batteries across California planning processes. In particular, the more granular assessment of resources to load forecast within individual LCR areas could be an important input to the Integrated Resource Planning (IRP) process. Incorporating these considerations will allow for more reliable and realistic resource portfolios that will serve California's energy needs.

********End of Informal Comments********

MARCH FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Revise General Order 156 to Include Certain Electric Service Providers and Community Choice Aggregators and Encourage Voluntary Participation by Other Non-Utility Entities Pursuant to Senate Bill 255; Consider LGBT Business Enterprise Voluntary Target Procurement Percentage Goals; Incorporate Disabled Business Enterprises; Modify the Required Reports and Audits; and Update Other Related Matters.	R.21-03-010

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION

Evelyn Kahl
General Counsel and Director of Policy
Leanne Bober
Senior Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94520
(415) 254-5454
regulatory@cal-cca.org

March 1, 2022

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page

Caselaw

Constitutional Provisions

Other

California Public Utilities Commision Proceedings

California Public Utilities Code

California Public Utilities Commission Decisions

California Public Utilities Commission Rules of Practice and Procedure

SUBJECT MATTER INDEX

SPECIFICATION OF ERROR

1. The Proposed Decision and the Proposed Decision's revised General Order 156 (GO 156) fail to incorporate the express limits of Public Utilities Code Section 366.2(m) on participation of community choice aggregators (CCA) in the Commission's Supplier Diversity Program due to California Proposition 209 prohibitions on CCA preferential contracting.

2. The Proposed Decision and the Proposed Decision's revised GO 156 unlawfully apply the workforce and board diversity reporting requirements to CCAs.

RECOMMENDED CHANGES

1. Modify the Proposed Decision and the Proposed Decision's GO 156 as set forth in Attachments A and B hereto to limit the requirements on CCAs as set forth in Section 366.2(m) to ensure CCAs remain in compliance with Proposition 209.

2. Modify the Proposed Decision and the Proposed Decision's GO 156 to allow CCAs to voluntarily report on workforce and board diversity to the extent practicable and permitted by law.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Revise General Order 156 to Include Certain Electric Service Providers and Community Choice Aggregators and Encourage Voluntary Participation by Other Non-Utility Entities Pursuant to Senate Bill 255; Consider LGBT Business Enterprise Voluntary Target Procurement Percentage Goals; Incorporate Disabled Business Enterprises; Modify the Required Reports and Audits; and Update Other Related Matters.	R.21-03-010

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION

The California Community Choice Association (CalCCA)[1] submits these Comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Revising General Order 156 Supplier Diversity Program to Implement Senate Bill 255, Adopt a Voluntary Procurement Goal for LGBT Business Enterprises, Incorporate Persons with Disabilities Business Enterprises, and Other Updates* (Proposed Decision or PD), issued on February 9, 2022.

[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

I. INTRODUCTION

The PD and the PD's proposed revisions to General Order 156 (GO 156) aim to implement Senate Bill (SB) 255 which, among other items, adds Section 366.2(m) to the Public Utilities Code. Section 366.2(m) incorporates Community Choice Aggregators (CCAs) into the Commission's Supplier Diversity Program (Program) by imposing distinct reporting requirements on CCAs. Since SB 255 was adopted in 2019, Commission staff has guided the CCAs through the requirements of Section 366.2(m), resulting in the 2021 filings of the first CCA Supplier Diversity Annual Reports and Plans. This Rulemaking proposes to formalize the requirements of SB 255 in GO 156.

The Commission incorporates CCAs into GO 156 for the first time through the PD and GO 156 revisions. However, the revisions unlawfully sweep CCAs into all of the requirements imposed on investor-owned utilities (IOUs) and electric service providers (ESPs), failing to accurately implement the distinct limitations on application of GO 156 to CCAs set forth in Section 366.2(m). The PD rests on the following legal errors:

- The Proposed Decision and the Proposed Decision's revised General Order 156 (GO 156) fail to accurately incorporate the express limits of Section 366.2(m) on participation of community choice aggregators (CCA) in the Commission's Supplier Diversity Program due to California Proposition 209 prohibitions on CCA preferential contracting.
- The Proposed Decision and revised GO 156 unlawfully apply the workforce and board diversity reporting requirements on CCAs.

The Commission should modify the PD as follows to correct these legal errors:

- ✓ Modify the Proposed Decision and GO 156 as set forth in Attachments A and B hereto to limit the requirements on CCAs as set forth in Section 366.2(m) to ensure CCAs can remain in compliance with Proposition 209.
- ✓ Modify the Proposed Decision and GO 156 to allow CCAs to voluntarily report on workforce and board diversity to the extent practicable and permitted by law.

II. BACKGROUND

A. The Supplier Diversity Program and SB 255's Addition of Community Choice Aggregators and Electric Service Providers

Public Utilities Code Sections 8281-8286 contain the original framework adopted in 1986 for the Program, encouraging utilities to award a share of procurement contracts to women and minority business enterprises.[2] Sections 8281-8286 have been amended over the years to incorporate additional categories of suppliers including disabled veteran and lesbian, gay, bisexual, or transgender (LGBT) owned business enterprises (BEs). Sections 8281-8286, applicable to IOUs, include mandates that the Commission: (1) follow overall state policies governing supplier diversity; (2) require that IOUs file annual reports and plans including goals and timetables for increasing procurement from women, minority, disabled veteran, and LGBT BEs, (3) establish guidelines for supplier diversity programs; (4) require IOUs to annually submit data on diverse procurement; (5) adopt criteria for eligibility of diverse suppliers; (6) require IOUs to implement outreach programs to recruit diverse suppliers; and (7) enforce penalties for false representations of diversity by suppliers.[3] The Commission adopted GO 156 in 1988 (and has revised it several times since) to implement the statutory directives set forth in Sections 8281-8286.[4]

---

2 Assembly Bill 3678 (Moore 1986) (implementing the Supplier Diversity Program).
3 Cal. Pub. Util. Code §§ 8281-8286.
4 PD at 3.

The legislature passed SB 255 in 2019, adding two types of participants to the Program – ESPs and CCAs.[5] ESPs, but not CCAs, were expressly incorporated into all of the Program's requirements set forth in Sections 8281-8286.[6] CCAs were only incorporated into the Program through the addition of Public Utilities Code Section 366.2(m), which places the following distinct reporting requirements on operating CCAs with gross annual revenues exceeding $15 million:

- ✓ "[S]ubmit a detailed and verifiable ***plan*** to the commission for increasing procurement from ***small, local, and diverse business enterprises*** in all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects."[7]
- ✓ "[S]ubmit a ***report*** to the Commission regarding its procurement from ***women, minority, disabled veteran, and LGBT business enterprises*** in all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects."[8]

As discussed below, the statutory framework for CCAs was carefully crafted by the legislature to ensure that the rules would not infringe on the prohibitions against discrimination through public contracting imposed on CCAs (and inapplicable to IOUs and ESPs) through California Proposition 209.[9]

B. Proposition 209 – Applicable to Community Choice Aggregators

Proposition 209, passed as a California constitutional amendment on November 5, 1996, orders that "[t]he state shall not discriminate against, or grant preferential treatment to, any individual or group on the basis of race, sex, color, ethnicity, or national origin in the operation

---

5 SB 255 (Bradford 2019).

6 *Id.*

7 Cal. Pub. Util. Code § 366.2(m)(1) (emphasis supplied).

8 *Id.,* § 366.2(m)(2) (emphasis supplied). The only other requirement is that a CCA in the process of forming must include in its implementation plan its methods to ensure procurement from small, local and diverse business enterprises. *Id.,* § 366.2(c)(3)(H).

9 *See* Senate Rules Committee, SB 255 (Sept. 9, 2019), at 5-6.

of public employment, public education, or public contracting."[10] "State" includes "any city, county, city and county, … or any other political subdivision or governmental instrumentality of or within the State."[11] CCAs, as agencies within local counties or cities, fall within Proposition 209's definition of "State" and therefore are subject to its limitations.[12]

For best practice compliance with Proposition 209, CCA procurement should be complete, and a contract awarded, before a CCA can survey a vendor regarding any certification or qualification under the Program. Once the information is collected, the CCA must take appropriate measures to keep this information out of any discussion of future procurement to avoid violating Proposition 209. CCAs also cannot recruit or set procurement targets for the classified groups set forth in Proposition 209. For the Annual Reports and Plans required by Section 366.2(m), CCA Annual Plans are required to contain ***future*** contracting plans only with small, local and diverse vendors (*i.e.*, not including the classified groups subject to Proposition 209 limitations). For the Annual Reports, CCAs can report on the ***past year's*** procurement from the classified groups subject to Proposition 209 limitations and still remain in compliance with Proposition 209.

C. 2021 CCA First Supplier Diversity Annual Reports/Plans

Since SB 255 was passed, Commission staff have worked closely with CCAs to implement and interpret the unique reporting requirements applicable to CCAs. The fourteen CCAs subject to SB 255's reporting requirement thresholds submitted their first Supplier

---

10 California Constitution, Article 1, Section 31(a), located at: https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=CONS&division=&title=&part=&chapter=&article=I

11 *Id.,* Section 31(f).

12 The Commission's Staff Proposal recognizes that "CCAs are considered municipalities and must follow [Proposition 209] . . . ." *Staff Proposal to Revise General Order 156 for the Supplier Diversity Program,* R.21-03-010 (July 16, 2021), at 11.

Diversity 2020 Report and 2021 Plan on March 1, 2021.[13] The Commission's report to the Legislature in September 2021 lauded the achievements of CCAs in their first year of participation in the Program:

> The CPUC congratulates the CCAs for taking the initial steps towards supplier diversity despite the challenges, specifically Proposition 209. Currently, the CPUC is working with the CCAs and organizations in the energy industry to find solutions, provide guidance, identify best practices, engage diverse suppliers, and build relationships with ethnic chambers of commerce and local business organizations.[14]

Subsequent meetings and workshops between the CCAs and Commission Staff have further defined the content of the CCA Reports and Plans required by Section 366.2(m). The CCAs look forward to their continuing collaboration with Commission Staff to improve the Reports and Plans and the CCAs' supplier diversity efforts.

III. THE PROPOSED DECISION FAILS TO ACCURATELY IMPLEMENT SECTION 366.2(M) INTO GO 156 RESULTING IN LEGAL ERROR

This Rulemaking includes formalizing the requirements of SB 255 into the Commission's GO 156, and therefore for the first time incorporates ESPs and CCAs into GO 156. While ESPs are appropriately added to the provisions applicable to IOUs consistent with SB 255, the PD and revisions to GO 156 also subject CCAs to the same requirements and therefore inaccurately incorporate the requirements of Section 366.2(m), resulting in legal error. Accordingly, the PD and revised GO 156 must be materially modified as set forth in Attachments A and B attached hereto.

---

13 *See* https://www.cpuc.ca.gov/about-cpuc/divisions/news-and-public-information-office/business-and-community-outreach/utility-supplier-diversity-program/community-choice-aggregators-supplier-diversity-reports.

14 *See* *California Public Utilities Commission Year 2020 Utilities Procurement of Goods, Services, and Fuel From Women, Minority, Disabled Veteran, and LGBT Business Enterprises* (Sept. 2021), at 51.

A. The Limited Statutory Mandates for Including CCAs in the Commission's Supplier Diversity Program are Unambiguously Set Forth in Public Utilities Code Section 366.2

SB 255 was carefully crafted to add CCAs to the Program through Section 366.2(m) considering the limitations posed by Proposition 209. The plain language of Section 366.2(m) requires CCAs only to state in their Annual Plans how they can increase procurement in the next year from small, local, and diverse business enterprises (which are not classified groups subject to Proposition 209 limitations). The requirements for CCAs differ from the requirements on IOUs and ESPs in Section 8283(a) to report in their Annual Plans on procurement goals for, as well as increasing recruiting and contracting with, eligible suppliers, which includes classified groups subject to Proposition 209 limitations. The requirements for the Annual Reports of IOUs, ESPs, and CCAs, however, are identical in Sections 8283(d) for IOUs and ESPs, and Section 366.2(m)(2) for CCAs, both of which require reports on the past year's contracting with eligible suppliers (including classified groups subject to Proposition 209 limitations).

In interpreting its statutory authority, such as here when incorporating Section 366.2(m) into GO 156, the Commission is to "ascertain the Legislature's intent so as to effectuate the purpose of the law."[15] To that end, the Commission must "look first to the words of the statute, giving the language its usual, ordinary meaning."[16] The Commission has observed that when interpreting a statute, it must:

> [L]ook to the statute's words and give them their usual and ordinary meaning. The statute's **plain meaning** controls the court's interpretation unless its words are ambiguous. If the statutory language permits more than one reasonable interpretation, courts may consider other aids, such as the statute's purpose, legislative history, and public policy….[17]

---

15 *Hunt v. Superior Court,* 21 Cal.4th 984, 1000 (1999) 31 Cal.4th 1051, 1056 (citations omitted).

16 *Ibid.*

17 D.12-05-035 (quoting *Imperial Merchant Services, Inc. v. Hunt* (2009) 47 Cal.4th 381, 387-388).

Here the statutory provisions in Sections 8281-8286 and 366.2(m) are very clear as to the Program requirements for IOUs, ESPs and CCAs.

Even if the Commission finds the statutory language ambiguous, however, the legislative history clarifies that the legislature was keenly aware of the legal restrictions on CCAs posed by Proposition 209:

> [l]egal restrictions make obtaining information related to protected classes challenging. California's Proposition 209 prohibits the State from discriminating against or granting preferential treatment to any individual or group on the basis of race, sex, color, ethnicity, or national origin in the operation of public employment, public education, or public contracting. The Proposition limits the degree to which any governmental entity within California, including CCAs, can compel information about certain protected classes to support contract decision-making. However, the Proposition does not prohibit after-the-fact reporting on outcomes from contracting. This bill requires CCAs to develop plans for small, local, and diverse business contracting; however, it requires CCAs to report after-the-fact on contracting with [protected classes].[18]

SB 255 therefore incorporates CCAs into the Program not by imposing the broad requirements of Sections 8281-8286 on CCAs, but rather only imposing distinct reporting requirements set forth in Section 366.2(m).

B. The PD and Proposed GO 156 Must Be Modified to Accurately Incorporate CCAs into GO 156

In the PD, the Commission appropriately "finds it reasonable to permit more limited reporting requirements for [CCAs] than those currently required of utilities."[19] The Commission relies on Public Utilities Code Section 366.2(m)(2)(B)[20] providing the Commission discretion to determine the form of reporting for CCAs which can differ from that applicable to IOUs and

[18] Senate Rules Committee, Analysis of SB 255 (Sept. 9, 2019), at 5.
[19] PD at 16.
[20] The PD states that the Commission is relying on Pub. Util. Code § 399.2(m)(2)(B) which appears to be in error – the correct section is 366.2(m)(2)(B).

ESPs.[21] The PD and Section 11 of the GO 156 revisions also reflect that approximately 94 percent of CCA expenditures are in power procurement, which has few eligible suppliers as represented in the reports of utilities, ESPs and CCAs.[22] Therefore Section 11 of the PD's revisions to GO 156 states that the reporting requirements may be modified to reflect the unique situation of CCAs with respect to diverse spend in power procurement, and then diverse spend for non-power procurements categories. However, while the Commission noted CalCCA's concern of a legal conflict for CCAs to comply with both Proposition 209 and the existing GO 156 reporting requirements, the Commission failed to address this concern in both the PD and the proposed GO 156 revisions.[23]

The PD and the proposed revisions to GO 156 must be modified to remove requirements for CCAs that fall outside of the statutory mandates set forth in Section 366.2(m). As currently drafted, the rules sweep CCAs into the same requirements as IOUs and ESPs with respect to not only the Reports and Plans, but also recruitment and procurement goals for diverse suppliers that would violate Proposition 209 and are set forth throughout GO 156, and particularly in Sections 6 (Implementation by Utilities and Other Covered Entities), 8 (Procurement Goals), 9 (Required Annual Reports), and 10 (Required Annual Plans). In fact, the new Section 11 specific to CCAs states that the CCA Reports and Plans "will still include the information in Section 9 and Section 10, herein," requiring Reports and Plans to contain efforts to recruit eligible suppliers and meet procurement goals, both of which were excluded by Section 366.2(m) specifically to avoid CCA

---

21 PD at 16.

22 For example, the Commission's Year 2020 report to the Legislature on Supplier Diversity noted the challenges in diversifying power procurement for utilities in 2020. *See* *California Public Utilities Commission Year 2020 Utilities Procurement of Goods, Services, and Fuel From Women, Minority, Disabled Veteran, and LGBT Business Enterprises* (Sept. 2021) at 45-46 (2020 diverse percentage of spend in power procurement versus total procurement spend: PG&E – 0.05%; SCE – 0.6%; SDG&E – 2.5%).

23 PD at 14.

violations of Proposition 209. In addition, Section 1.2 of the revised GO 156 specifically applies ***all*** of the rules set forth in GO 156 to CCAs with gross annual revenues exceeding $15,000,000, which would sweep CCAs into ***all*** of the recruitment, procurement target and other provisions outside of the requirements of Section 366.2(m). In short, GO 156 would place requirements on CCAs that could result in violations of Proposition 209, which was not intended by the legislature in enacting SB 255. For these reasons, adoption of the PD and the PD's proposed revised GO 156 would constitute legal error.

Attachment B, attached hereto, contains the redline revisions necessary to prevent such legal error.[24] Importantly, all of CalCCA's proposed revisions are consistent with and follow the guidance provided by Commission staff concerning the reporting requirements for CCAs. As noted in CalCCA's April 12, 2021 Response to the Order Instituting Rulemaking in this proceeding, Commission Staff sent an e-mail to CCAs on April 1, 2020 containing draft templates and a checklist (attached to those Comments as Appendix A-2) explaining which GO 156 reporting categories were applicable to CCAs and which were not.[25] Since that time, Commission Staff and the CCAs have engaged in substantial discussions, meetings, and workshops to tailor the reporting requirements to ensure CCAs are in compliance with Section 366.2(m). Therefore, the revisions to GO 156 set forth in Attachment B hereto must be adopted to incorporate those discussions, ensure compliance with Section 366.2(m), and prevent the legal error which currently exists in the PD and the PD's proposed revised GO 156.

---

[24] Proposed revisions to Section 14 are discussed in Section IV. of these Comments.

[25] R.21-03-010, *California Community Choice Association's Comments on Order Instituting Rulemaking to Revise General Order 156 – Supplier Diversity Program* (Apr. 12, 2021).

IV. THE PD AND REVISED GO 156 MUST BE MODIFIED TO ALLOW CCAS TO REPORT ON WORKFORCE AND BOARD DIVERSITY TO THE EXTENT PRACTICABLE AND PERMITTED BY LAW

The PD and proposed revisions to GO 156 incorporate requirements for IOUs, ESPs and CCAs to report on workforce and board diversity beginning in March of 2024 (reflecting 2023 data). The Commission, however, has no explicit authority, either through SB 255 or any other statute, to require CCAs to report on workforce and board diversity.[26] Instead, the Commission uses its general authority under Section 8281 to "realize the economic well-being of the state of California by encouraging diversity and inclusion within the utility industry through transparent reporting."[27] Section 8281, however, applies to "regulated public utilities," and not CCAs. In addition, the PD's analysis of such reporting requirements relies upon interpretation of state law applicable to corporations. CCAs are public entities with elected or appointed boards and have no control over the makeup of their boards. Even if CCAs did have some control over their governing board composition, CCAs would be limited by Proposition 209 in their ability to recruit potential board members based on classified group status. Therefore, in many pertinent ways, CCAs are distinguishable from corporations and limited in their ability to ensure diversity throughout their boards and workforce.

Despite the limitations on CCA workforce and board diversity reporting and the lack of statutory authority of the Commission to require it, CCAs do generally agree that collecting such information is important to understand the status of diversity within the energy industry. In fact, several CCAs are already collecting such information to the extent possible and including it in

---

26 *Id*.

27 PD at 44, 49.

their Supplier Diversity Annual Reports.[28] Therefore, CalCCA's revisions to GO 156 set forth in Attachment B, hereto, acknowledge that CCAs may provide information concerning workforce and board diversity in their Annual Reports, starting March 2024 (or earlier if possible), to the extent practicable and permitted by law.

V. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and requests adoption of the recommendations proposed herein. For all the foregoing reasons, the Commission should modify the PD and revised GO 156 as provided in Attachments A and B.

Respectfully submitted,

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

March 1, 2022

[28] For example, Clean Power Alliance provided staff diversity data based on voluntary self-reporting in its 2020-21 Annual Report & Plan and expects to collect board diversity data from voluntary surveys beginning in 2021. In addition, Sonoma Clean Power provided information on its internal polices focusing on diversity and equity in its 2020 Annual Report and 2021 Annual Plan.

ATTACHMENT A

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

PROPOSED DECISION

P. 16: In making this decision, we rely on Pub. Util. Code § ~~399.2(m)(2)(B)~~366.2(m)(2)(B), which provides the Commission with discretion to create reporting requirements for community choice aggregators that are different from those applicable to utilities.

FINDINGS OF FACT

7. Establishing a LGBT voluntary procurement goal for utilities and electric service providers is critical for increasing the engagement and participation of LGBT business enterprises in the Supplier Diversity Program set forth in GO 156.

20. Incorporating workforce data pertaining to women, minorities, disabled veterans, persons with disabilities, and LGBT into the GO 156 annual reports will increase the Commission's understanding of the composition of the workforce of~~the covered entities~~ the utilities and electric service providers and will not be overly burdensome, as it reflects information many of these ~~covered entities~~utilities and electric service providers already collect.

CONCLUSIONS OF LAW

1. More limited mandatory reporting requirements for community choice aggregators than those currently required of utilities is reasonable based on Pub. Util. Code § ~~399.2(m)(2)(B)~~366.2(m)(2)(B), which provides the Commission with discretion to create reporting requirements for community choice aggregators that are different from those applicable to utilities.

17. Requiring ~~covered entities~~utilities and electric service providers under GO 156 to provide workforce data pertaining to persons who identify as women, minorities, disabled veterans, persons with disabilities, and LGBT into their GO 156 annual reports is reasonable because it will increase the Commission's understanding of the composition of the workforce of~~the covered entities~~ utilities and electric service providers and will not be overly burdensome, as it reflects information many of these entities already collect, and is consistent with Commission authority. Community choice aggregators may provide such workforce data to the extent practicable and permitted by law. This reporting will commence with the GO 156 annual reports beginning in March of 2024 (reflecting 2023 data) and in all future annual reports.

18. Based on the intent of recent state legislation in SB 826 (Jackson, 2018) and AB 979 (Holden, 2020) to increase the diversity of board representation, it is reasonable to track the board diversity by requiring ~~covered entities under GO 156, *i.e.,*~~utilities~~, community choice aggregators,~~ and electric service providers that meet certain revenue thresholds, to

report on the number of persons serving on their boards that identify as women, minorities, disabled veterans, persons with disabilities, and LGBT in the GO 156 annual reports beginning in March of 2024 (reflecting 2023 data) and in all future annual reports. Community choice aggregators may provide such board composition data to the extent practicable and permitted by law.

ORDERING PARAGRAPHS

No changes.

ATTACHMENT B

**CALCCA PROPOSED REVISIONS TO PD,
APPENDIX B (CLEAN VERSION OF GENERAL ORDER 156)**

PROPOSED DECISION

FILED
02/09/22
02/09/22
11:44 AM

PUBLIC UTILITIES COMMISSION OF THE STATE OFCALIFORNIA

RULES GOVERNING THE DEVELOPMENT OF PROGRAMS TO INCREASE PARTICIPATION OF WOMEN, MINORITY, DISABLED VETERAN, LESBIAN, GAY, BISEXUAL AND TRANSGENDER (LGBT)' AND PERSONS WITH DISABILITIES BUSINESS ENTERPRISES IN PROCUREMENT OF CONTRACTS FROM UTILITIES, COMMUNITY CHOICE AGGREGATORS, AND ELECTRIC SERVICE PROVIDERS, AS REQUIRED BY PUBLIC UTILITIES CODE SECTIONS 366.2 and 8281-8286

Adopted April 27, 1988. Effective May 30, 1988.
Decision (D.) 88-04-057 in Rulemaking 87-02-026.

Modified by D.88-09-024, D.89-08-041, D.90-11-053, D.90-12-027, D.92-06-030, D.95-12-045, D.96-12-081, D.98-11-030, D.03-11-024, D.05-12-023, D.06-08-031, D.11-05-019, D.15-06-007, and ________________. Also modified by Resolution Exec-001 and Resolution ALJ-377.

TABLE OF CONTENTS

6. UTILITY IMPLEMENTATION

6.1. Internal Utility Program Development

6.1.1. Employee training

6.2. External Outreach

6.2.1. Outreach activities

6.3. Subcontracting Program

6.3.1. Subcontracting program to enhance, not replace prime contractor outreach program

6.3.2. Application of subcontracting program

6.3.3. Contracts not subject to subcontracting requirements

6.3.4. Development of subcontracting programs by prime contractors

6.3.5. Eligible Supplier notice in bids

6.3.6. Inclusion of statement that subcontracting with Eligible Suppliers is a factor to be considered in bid evaluation process

6.3.7. Inclusion of prime contractor progress in utility's annual report

6.3.8. Inclusion of subcontractor plans in utility's annual plan

6.3.9. Inclusion of subcontractor awards in utility's Eligible Supplier results

7. REVIEW PROCESS, NOTICES OF APPEAL, AND COMPLAINT PROCESS

7.1. Internal Appeal of Clearinghouse Verification Denials

7.2. Notice of Appeals

7.3. Third-Party Challenges

7.4. Contract Disputes

8. PROCUREMENT GOALS

9. REQUIRED ANNUAL REPORT

9.1. Contents of Report

9.1.1. Description of program activities

9.1.2. Summary of purchases/ contracts

9.1.3. Itemization of program expense

9.1.4. Description of progress in meeting or exceeding set procurement goals

9.1.5. Summary of prime contractor utilization of subcontractors

9.1.6. List of complaints about the programs of the utility and other covered entities

9.1.7. Summary of purchases/contracts for products/services in excluded categories

9.1.8. Description of efforts to recruit Eligible Suppliers

9.1.9. Justification for continued existence of any "excluded category"

9.1.10. Summary of purchases in product and service categories that include renewable and non-renewable energy, wireless communications, broadband, smart grid, and rail projects, in addition to their current reporting categories.

9.1.11. File verifiable report on participation of Eligible Suppliers in fuel markets

1. GENERAL

1.1. Intent

1.1.1. Purpose - These rules implement California Public Utilities Code (Pub. Util. Code) ~~§ 366.2 and~~ §§ 8281-8286, which requires the Commission to establish rules for ~~(1) electric~~ utilities (as defined herein) and other covered entities (as defined herein)~~, gas utilities, water utilities, wireless telecommunications service providers, telephone utilities, and electric service providers with gross annual California revenues exceeding $15,000,000 and their commission-regulated subsidiaries and affiliates~~ ~~and (2) community choice aggregators with gross annual revenues exceeding $15,000,000~~ to submit annual plans and reports for purposes of increasing procurement in all categories from business enterprises owned and controlled by women, minority, disabled veteran, LGBT, and persons with disabilities. These rules also implement ~~Pursuant to~~Public Utilities Code § 366. 2(m)(1) and (2), ~~these rules also~~ which mandate that the Commission require ~~direct~~ each community choice aggregator as defined herein to (1) annually submit a detailed and verifiable plan~~s~~ ~~to address~~ for increasing procurement from small, ~~and~~ local, and diverse business enterprises, and (2) annually submit a report regarding its procurement from women, minority, disabled veteran, and LGBT business enterprises. ~~in annual plans. Non- utility entities, meaning electric service providers and community choice aggregators, that must comply with the annual report and annual plan requirements under Pub. Util. Code §366.2 and §§ 8281-8286 are referred to herein as “other covered entities.”~~

1.1.2. Scope - These rules may be revised on the basis of experience gained in their application and/or changes in legislation.

1.1.3. Relief for Hardship - In cases where these rules result~~s~~ in undue hardship or unreasonable expense to a utility, ~~or~~ other covered entity, or community choice aggregator, the utility, ~~or~~ other covered entity, or community choice aggregator may request relief from the Commission in accordance with the Commission's Rules of Practice and Procedure. Where the relief requested is of minor importance or temporary in nature, the utility, other covered entity, or community choice aggregator may apply for such relief through an advice letter filing. Any advice letter filing must, at a minimum, be served on all parties on the service list of this proceeding.

1.2. Applicability

These rules apply to ~~electric~~ utilities (as defined herein), and other covered entities (as defined herein).~~, gas utilities, water utilities, wireless telecommunications service providers, telephone utilities, and electric service providers with gross annual California revenues exceeding $15,000,000 and their commission-regulated subsidiaries and affiliates.~~ These rules also apply to ~~all~~ community choice aggregators (as defined herein). ~~with gross annual California revenues exceeding $15,000,000~~. Nothing in these rules require a community choice aggregator to take any action that would violate Proposition 209 (as defined herein).

1.3. Definitions

1.3.1. "Commission" means the California Public Utilities Commission, as provided for in Article XII of the California Constitution.

1.3.2. "Women business enterprise" means (1) a business enterprise (a) that is at least 51% owned by a woman or women or (b) if a publicly owned business, at least 51% of the stock of which is owned by one or more women, and (2) whosemanagement and daily business operations are controlled by one or more of those individuals.

1.3.3. "Minority business enterprise" means (1) a business enterprise (a) that is at least 51% owned by a minority individual or group(s) or (b) if a publicly owned business, at least 51 % of the stock of which is owned by one or more minority groups, and (2) whose management and daily business operations are controlled by one or more of those individuals. The contracting utility shall presume that minority includes, but is not limited to, African Americans, Hispanic Americans, Native Americans, Asian Pacific Americans, and other groups as defined herein.

1.3.4. "LGBT business enterprise" means (1) a business enterprise (a) that is at least 51% owned by a lesbian, gay, bisexual, or transgender person or persons or

(b) if a publicly owned business, at least 51 % of the stock of which is ownedby one or more lesbian, gay, bisexual, or transgender persons; and (2) whose management and daily business operations are controlled by one or more of those individuals.

"Persons with disabilities business enterprise" means (1) a business enterprise (a) that is at least 51% owned by a person or persons with a disability or (b) if a publicly owned business, at least 51 % of the stock of which is owned by one or more persons with a disability; and (2) whose management and daily business operations are controlled by one or more of those individuals.

1.3.5. Under these rules, the persons owning an eligible supplier~~s~~ must be either U.S. citizens or legal aliens with permanent residence status in the United States.

1.3.6. "Disabled veteran" refers to a veteran of the military, naval or air service of the United States with a service-connected disability who is a resident of the Stateof California.

1.3.7. "Disabled veteran business enterprise" is defined in Section 4, herein.~~.~~

~~1.3.9. .~~

1.3.10. "African American person," for purposes of this General Order, refers to aperson having origins in any black racial groups of Africa.

1.3.11. "Hispanic American person," for purposes of this General Order, refers to aperson of Mexican, Puerto Rican, Cuban, South or Central American, Caribbean, and other Spanish culture or origin.

1.3.12. "Native American person," for purposes of this General Order, refers to a personhaving origin in any of the original peoples of North America or the Hawaiian Islands, in particular, American Indians, Eskimos, Aleuts, and Native Hawaiians.

1.3.13. "Asian Pacific American person," for purposes of this General Order, refers to aperson having origin in Asia or the Indian subcontinent, including, but not limited to, persons from Japan, China, the Philippines, Vietnam, Korea, Samoa, Guam, the U.S. Trust Territories of the Pacific, Northern Marianas, Laos, Cambodia, Taiwan, India, Pakistan, and Bangladesh.

1.3.14. "Other groups or individuals" means persons found to be disadvantaged by the Small Business Administration pursuant to Section 8(a) of Small Business Actas amended (15 U.S.C. 637 (a)), or the Secretary of Commerce pursuant to Section 5 of Executive Order 11625.

1.3.15. "Control" means exercising the power to make policy decisions.

1.3.16. To "operate" means to be actively involved in the day-to-day management. It is not enough to merely be an officer or director.

1.3.17. "Goal" means a target which, when achieved, indicates progress in a preferred direction. A goal is neither a requirement nor a quota.

1.3.18. "Excluded category" means a category of products or services which may be removed from the dollar base used to establish goals, pursuant to former Section 8.5 of this General Order, because of the established unavailability of eligible suppliers capable of supplying those products or services.

1.3.19. "Short-term goal" means a goal applicable to a period of one (1) year.

1.3.20. "Mid-term goal" means a goal applicable to a period of three (3) years.

1.3.21. "Long-term goal" means a goal applicable to a period of five (5) years.

1.3.22. "Utility" means electric utilities, gas utilities, water utilities, wireless telecommunications service providers, and telephone utilities with gross annual California revenues exceeding $15,000,000 and their Commission-regulated subsidiaries and affiliates.

1.3.23. The "Clearinghouse" means a Commission-supervised program or entity that shall conduct certifications/verifications and maintain a database of eligible suppliers for the use of utilities, ~~and~~ other covered entities, and community choice aggregators under the Commission's Supplier Diversity Program.~~.~~

1.3.24. "Subcontract~~"~~” means any agreement or arrangement between a contractor and any party or person (in which the parties do not stand in the relationship of an employer and an employee):

1.3.24.1. For the furnishing of supplies or services for the use of real or personal property, including lease arrangements, which, in whole or in part, is necessary to the performance of any one or more contracts; or

1.3.24.2. Under which any portion of the contractor's obligation under any one or more contracts is performed, undertaken or assumed.

1.3.25. "Product and service categories" means product and service categories as defined by the Standard Industrial Classification (SIC) system maintained by the United States Department of Labor, Occupational Safety and Health Administration, as they currently read or as amended or as defined by any other updated classification system that supersedes the SIC system.

1.3.26. “Proposition 209” means Article 1, Section 31 of the California Constitution (added November 5, 1996 by Proposition 209), which prohibits the “state,” subdivision or governmental instrumentality of or within the State,” from “discriminat[ing] against, or grant[ing] preferential treatment to, any individual or group on the basis of race, sex, color, ethnicity, or national origin in the operation of public employment, public education, or public contracting.” Community choice aggregators, as public entities, are subject to Proposition 209.

1.3.27. “Other covered entity” means electric service provider as that term is defined in Pub. Util. Code § 218.3 and used in Pub. Util. Code § 8281-8286.

1.3.28. “Community choice aggregator” means (1) an entity created pursuant to Pub. Util. Code §366.2; and (2) with gross annual California revenues exceeding $15,000,000, except where used herein to specifically reference community choice aggregators with gross annual California revenues of less than $15,000,000.

2. VERIFICATION

The following rules shall be used to verify the eligibility of business enterprises owned and controlled by women, minority, LGBT, or persons with disabilities for participation in procurement contracts under the Commission's Supplier Diversity Program.

2.1. The Clearinghouse, as described in Section 3, shall supply a verification form to applicants. An applicant may complete the verification form and return it to the Clearinghouse for processing. Suppliers that are certified/verified under GO 156 are referred to herein as "eligible suppliers".

2.2. In assessing the suitability of a supplier to bid for procurement contracts, a utility or other covered entity may require additional information or the completion of additional forms to comply with specific requirements created by the unique character of its business, such as insurance requirements, product and service codes, and bonding limits. A utility, ~~or~~ other covered entity, or community choice aggregator may not, however, require additional information to verify that a business is in fact an eligible supplier under the Commission's Supplier Diversity Program.

2.3. Eligible suppliers shall be required to submit verification forms at least once every three years to the Clearinghouse.

2.4. Completion and submission of the verification application to the Clearinghouse serves to initiate a verification of the business as an eligible supplier under the Commission's Supplier Diversity Program.

Submission of an application does not guarantee verification.

2.5. The fact that a business is verified as an eligible supplier under the Commission's Supplier Diversity Program and included in the Clearinghouse's database of eligible suppliers is not an endorsement of its ability to perform and does not guarantee contracts with the utilities, ~~or~~ other covered entities, or community choice aggregators.

2.6. An applicant's verification form shall be available for inspection by the Commission.

2.7. Falsification of information by the applicant on the verification form is subject to the penalties provided by Pub. Util. Code § 8285.

3. CLEARINGHOUSE

The Commission shall provide for a clearinghouse to share the name of and verification status of eligible suppliers under the Commission's Supplier Diversity Program.~~.~~

3.1. The Commission may establish and operate such a clearinghouse internally or authorize, by decision or resolution, a utility-formed entity or arrangement to fund the operation of such a clearinghouse. In authorizing a utility-formed entity or arrangement, the Commission will specify sufficient terms and conditions to specify how verifications and audits shall be performed and to ascertain and ensure that the Clearinghouse is operated in accordance with this General Order, Pub. Util. Code §§ 366.2, 8281-8286, and other applicable legal requirements.

3.2. The purpose of the Clearinghouse shall be to audit and verify the status of business enterprises as eligible suppliers under the Commission's Supplier Diversity Program, and to establish and maintain a database of eligible suppliers that is accessible to the Commission, utilities, ~~and~~ other covered entities, and community choice aggregators.

3.3. The Clearinghouse auditing and verification program of suppliers shall preclude the need for a utility, ~~or~~ other covered entity, or community choice aggregator to audit and verify whether a business enterprise is an eligible supplier under the Commission's Supplier Diversity Program.

3.4. The Clearinghouse shall distribute renewal verification forms to the eligible suppliers that are already verified at least once every three years. If the eligible supplier does not complete and return the renewal within a reasonable time, the Clearinghouse shall notify the eligible supplier that the eligible supplier will not be listed as an eligible supplier in the shared database until the renewal is completed and approved.

3.5. The Clearinghouse shall post on its website a calendar of procurement-related information sharing and educational events and activities scheduled by utilities,

~~and~~other covered entities, and community choice aggregators in furtherance of legislative policy and this General Order andmay post additional information regarding procurement and/or educational opportunities.

3.6. In addition to the Clearinghouse, the Commission may approve of third-party agencies to perform verifications of applicants. The Clearinghouse is authorized to accept certifications by approved third-party agencies, as appropriate, and to develop and implement a streamlined comparable agency verification process for any applicant that already has a certification through an approved third-party agency.[2] After the Commission has approved of a third-party agency~~(~~, applicants may choose between the option of (1) going directly to the Clearinghouse for verification or (2) through an approved third-party agency, followed by a streamlined verification process with the Clearinghouse. If an applicant already has a certification through an approved third-party agency, the applicant is encouraged toapply to the Clearinghouse through the streamlined verification process.

3.7. The following shall be the process for a third-party agency seeking to become a verifying agency under this General Order:

(a) The requesting third-party agency shall submit a written request (herein "Request") to the Commission's GO 156 Staff;

(b) The Request shall include a detailed explanation showing that the requesting third-party agency's objectives, eligibility requirements, required documentation, and review and certification processes are substantially similar to those of the Clearinghouse;

(c) The Commission's GO 156 Staff must evaluate the Request and make a recommendation to the Commission within 60 days of receiving a Request;[1] and

(d) Upon review of the Request by the Commission's GO 156 Staff, the GO 156 Staff will publish a draft resolution under the Commission's Rules of Practice and Procedure granting or denying the requesting third-party agency its verifying agency status. This draft resolution shall be placed on the Commission's Agenda for a vote.

4. DISABLED VETERANS

The following rules shall apply to disabled veteran business enterprises (also referred to as "DVBE"). The term "disabled veteran" is defined in Section 1.3.6 of this General Order.

4.1. "Disabled veteran business enterprise" is defined in Military and Veterans Code § 999, as required by D.92-06-030, to mean a business enterprise certified by the California Department of General Services as meeting all of the following requirements.

4.1.1. It is a sole proprietorship at least 51 percent owned by one or more disabled veterans or, in the case of a publicly owned business, at least 51 percent of its stock is owned by one or more disabled veterans; a subsidiary which is wholly owned by a parent corporation, but only if at least 51 percent of the voting stock of the parent corporation is owned by one or more disabled veterans; or a joint venture in which at least 51 percent of the joint venture's management and control and earnings are held by one or more disabled veterans.

4.1.2. The management and control of the daily business operations are by one or more disabled veterans. The disabled veterans who exercise management and control are not required to be the same disabled veterans as the owners of the business concern.

---

[1] *See e.g.*, D.06-08-031 and Resolution Exec.-001 (July 9, 2009).

[1]All references to "days" shall be calculated as set forth in Rule 1.15 of the Commission's Rules of Practice and Procedure.

4.1.3. It is a sole proprietorship, corporation, or partnership with its home office located in the United States, which is not a branch or subsidiary of a foreign corporation, foreign firm, or other foreign-based business.

4.2. Pursuant to Pub. Util. Code § 8284(a)(2), DVBEs are verified/certified by the California State Department of General Services. The Office of Small Business and Disabled Veterans Business Enterprise Services currently performs this verification/certification. The Clearinghouse shall accept the verifications/certifications by the Department of General Services as though the DVBE has been verified/certified by the Clearinghouse and include such DVBE in the Clearinghouse's database of the verified/certified eligible suppliers .

4.3. In order to qualify as a DVBE, a business enterprise must meet the criteria in Section 4.1 and must present a current certificate from the California State Department of General Services verifying that such criteria have been met.

5. LESBIAN, GAY, BISEXUAL AND TRANSGENDER[2]

Pursuant to D.15-06-007, the following additional rules shall apply to LGBT business enterprises (also referred to as "LGBTBEs"). By or before September 1, 2015, the Clearinghouse shall begin maintaining the database associated with the LGBTBEs for purposes of the Commission's Supplier Diversity Program.

6. IMPLEMENTATION BY UTILITIES, ~~AND~~ OTHER COVERED ENTITIES, AND COMMUNITY CHOICE AGGREGATORS

Each utility, ~~and~~ other covered entity~~.~~, and community choice aggregator (to the extent permitted by Proposition 209) shall design and implement a program to ensurethat eligible suppliers in the Commission's Supplier Diversity Program are encouragedto become eligible suppliers of products and services to the utilities, ~~and~~ other covered entities, and community choice aggregators subject to GO 156. Nothing in GO 156 authorizes or permits a utility, ~~or~~ other covered entity, or community choice aggregator to utilize set-asides, preferences, or quotas in the administration of its program in compliance with GO 156. The utility, ~~or~~ other covered entity, or community choice aggregator retains authority to use its legitimate business judgment to select the supplier for a particularcontract.

6.1. Internal Program Development by Utilities, ~~and~~ Other Covered Entities, and Community Choice Aggregators

Each utility, ~~or~~ other covered entity, or community choice aggregator shall maintain an appropriately sized staff to provide overall direction and guidance and to implement their own program requirements consistent with the Commission's Supplier Diversity Program and applicable law. Each utility, ~~and~~ other covered entity, and community choice aggregator shall provide the email address and telephone numberof a contact person on the website of the utility, ~~or~~ other covered entity, or community choice aggregator in a prominentlocation so that eligible suppliers and applicants are able to obtain more information about these internal programs.

6.1.1. Each utility, ~~or~~ other covered entity, or community choice aggregator shall ensure that its staff with procurement responsibilities receive training in the implementation of the Commission'sSupplier Diversity Program.

6.2. External Outreach by Utilities, ~~and~~ Other Covered Entities, and Community Choice Aggregators

6.2.1. Utilities and Other Covered Entities

6.2.1.1 Each utility or other covered entity shall implement an outreach program to informand recruit eligible suppliers to apply for procurement contracts.

6.2.1.2 Outreach activities may vary for each utility or other covered entity dependingon size, service territory, and specific lines of business. However, each utility or other covered entity shall, at a minimum:

a) Actively seek out opportunities to identify eligible suppliers under the Commission's Supplier Diversity Program and to expand source pools;

b) Actively support the efforts of organizations experienced in the field who promote the interests of eligible suppliers under the Commission's Supplier Diversity Program;

c) Work with eligible suppliers under the Commission's Supplier Diversity Program to facilitate contracting relationships by explaining qualification requirements, bid and contracting procedures, materials requirements, invoicing and payment schedules, and other procurement practices and procedures;

d) At the request of any unsuccessful bidder, provide information concerning the relative range/ranking of the bid as contrasted with the successful bid. Information on additional selection criteria, such as warranty periods, maintenance costs, and delivery capability, shall be provided when requested if disclosure would notviolate the proprietary nature of the specific contract element;

e) To the extent possible, make available to eligible suppliers under the Commission's Supplier Diversity Program lists of utility/other covered entity purchase/contract categories which offer them the best opportunityfor success;

f) Encourage employees involved in procurement activities to break apart purchases and contracts, as appropriate, to accommodate thecapabilities of eligible suppliers under the Commission's Supplier Diversity Program;

g) Summarize this General Order in outreach program handouts and electronic notices. Such summaries shall state that eligible suppliers under the Commission's Supplier Diversity

h) Offer the same assistance set forth in Section 6.2.1 to any interestedparty, upon request.

6.2.2. Community Choice Aggregators

6.2.2.1 Each community choice aggregator shall, to the extent permitted by Proposition 209, implement an outreach program to, at a minimum:

a) inform suppliers, including eligible suppliers under the Commission's Supplier Diversity Program, about opportunities to apply for procurement contracts; and

b) inform suppliers about, and provide assistance regarding, certification through, the Commission's Supplier Diversity Program Clearinghouse.

6.3. Subcontracting Program

6.3.1 Utilities and Other Covered Entities

6.3.1.1 Each utility or other covered entity shall establish and maintain a subcontracting program for the purpose of encouraging its contractors to utilizeeligible suppliers under the Commission's Supplier Diversity Program.

6.3.1.2 The subcontracting program shall serve as an enhancement to, and not as areplacement for, the utility's or other covered entity's outreach program to eligible suppliers under the Commission's Supplier Diversity Program.

6.3.1.3 The subcontracting program shall apply to the following:

6.3.2.1.1 Purchases/contracts exceeding $500,000 for products and services;

6.3.2.1.2 Construction contracts exceeding $1,000,000; and

6.3.2.1.3 Purchases/contracts which offer subcontracting opportunities, regardless of value, where appropriate.

6.3.1.4 The subcontracting program need not be applied to the procurement of products manufactured for general consumption, such as paper, pens, and thelike.

6.3.1.5 Each utility or other covered entity shall encourage and assist its prime contractors to develop plans to increase the utilization of eligible suppliers under the Commission's Supplier Diversity Program as subcontractors. Prime contractors shall be encouraged to submit to the utility or other covered entity plans that include goals for the utilization of eligible suppliers under the Commission's Supplier Diversity Program as subcontractors. These plans maybe incorporated into the contract between the utility or other covered entity and the prime contractor. The prime contractor may submit periodic reports on its compliance with the plan to the utility or other covered entity.

6.3.1.6 Each utility or other covered entity is encouraged to incorporate in all purchase orders, requests for bid proposals, and other appropriate procurement documents related to procurement efforts subject to the subcontracting program, a statement similar to the following:

UTILIZATION OF BUSINESS ENTERPRISES OWNEDand CONTROLLED BY WOMEN, MINORITIES, DISABLED VETERANS, LGBT, AND PERSONS WITHDISABILITIES

It is the policy of this company that business enterprises owned and controlled by women, minorities, disabled veterans, LGBT, and persons with disabilities (herein "diverse suppliers"') shall have the maximum practicable opportunity to participate in the performance of contracts.

However, this policy shall not be used to exclude any qualified businesses from participating in contracting opportunities.

The contractor agrees to use its best efforts to carry out this policy in the award of subcontracts to the fullest extent consistent with the efficient performance of this contract.

The contractor agrees to inform all prospective subcontractors of the opportunity to request from the Clearinghouse a verification application to be certified as a diverse supplier, return the completed application to the Clearinghouse for processing, and, if verified/certified, the prospective supplier will be included in the database, as a diverse supplier.

6.3.1.7 Each utility or other covered entity is encouraged to inform its prime contractors that the prime contractor's good faith efforts to subcontract witheligible suppliers under the Commission's Supplier Diversity Program is a factor that will be considered in the bid evaluation process. A statement to that effect could be included in all appropriate procurement documents.

6.3.1.8 Each utility or other covered entity shall monitor and include in its annualreport to the Commission a summary of progress and efforts by its prime contractors to increase the participation of eligible suppliers under the Commission's Supplier Diversity Program.

6.3.1.9 Each utility or other covered entity shall include in its annual plan to the Commission a description of future plans for encouraging both prime contractors and grantees to engage eligible suppliers under the Commission'sSupplier Diversity Program in all procurement categories which provide subcontracting opportunities.

6.3.1.10 Each utility or other covered entity may include awards to eligible suppliersubcontractors in its GO 156 reporting results.

6.3.2 Community Choice Aggregators

6.3.2.1 Each community choice aggregator with gross annual revenues over fifteen million dollars ($15,000,000) shall include in its annual report any eligible suppliers with whom a prime contractor or grantee of a community choice aggregator has engaged in contracts or subcontracts for all categories, including, but not limited to, renewable energy, energy storage systems, and smart grid projects.

7. REVIEW PROCESS, NOTICE OF APPEALS, AND COMPLAINTS

This section sets forth the review process for when an applicant seeks (1) a reconsideration of a denial to verify/certify by the Clearinghouse and (2) to file a Notice of Appeal with the Commission after the Clearinghouse confirms its denial. This section also sets forth a process for a third-party to challenge a verification/certification of an eligible suppler by the Clearinghouse.

7.1. Internal Review Process. The review process for a denial of verification/certification includes two steps. First, the applicant can seek internal review from the Clearinghouse. If the Clearinghouse confirms the denial, as the second step, the applicant can seek review of the denial with the Commission by filing a Notice of Appeal under Resolution ALJ-377 (or successor rules) and the processes set forth therein. This resolution is available on the Commission's website. Resolution ALJ-377

sometimes refers to Notice of Appeals as complaints.

7.1.1. The Clearinghouse must implement an efficient internal review process and must promptly provide a copy of confirmation or reversal of the denial to the applicant.

7.2. Notices of Appeal. The Notice of Appeal will be docketed as a formal proceeding. All docketed matters are accessible on the Commission's website. The Chief Administrative Law Judge shall designate an Administrative Law Judge to hear the Notice of Appeal.

7.2.1. The Administrative Law Judge shall make best efforts to notice the Notice of Appeal for hearing between 10 and 20 days after being assigned to hear the Notice of Appeal. The Administrative Law Judge may confer with parties to determine whether any material facts are in dispute prior to scheduling a hearing and consider whether a hearing is warranted. The Administrative LawJudge may, for good cause shown or upon agreement of the parties, grant a reasonable continuance of the hearing and, instead, schedule and notice the hearing beyond the time period noted above.

7.2.2. A party or jointly the parties may order an expedited transcript of the hearing. Costs may be associated with an order for an expedited transcript, in accordance with the Commission's requirements. In the absence of an expedited transcript, the Commission may address this matter after approximately 8 weeks, the length of time for preparation of a transcript (when no expedited order is placed).

7.2.3. A party may be represented at the hearing by an attorney or other representative.

7.2.4. At the hearing, the applicant carries the burden of proof and shall open and close but the Administrative Law Judge has the discretion to alter the order of presentation. Formal rules of evidence do not apply. All relevant and reliable evidence may be received in the discretion of the Administrative Law Judge. No deference will be accorded to the underlying denial by the Clearinghouse. The standard of proof is preponderance of evidence.

7.2.5. The Administrative Law Judge shall issue a draft resolution for the Commission's consideration resolving the Notice of Appeal as soon as possible but no later than 30 days after the record of the Notice of Appeal is submitted. The draft resolution will be placed on the Commission's first available agenda, consistent with the Commission's Rules of Practice and Procedure. In the event the transcript of the hearing is not available, the Administrative Law Judge may delay issuing a draft resolution. This timeline would therefore be longer than set forth in Resolution ALJ-377.

7.2.6. From the date the Notice of Appeal is filed and served to and including the date the Commission's final resolution is published, neither party (or an attorney or agent acting on behalf of a party) shall engage in ex parte communications, except for procedural matters. More information about ex parte communications is available in the Commission's Rules of Practice and Procedure.

7.3. Third-Party Challenges. A third-party may challenge the certification/verification by the Clearinghouse of an applicant/eligible supplier under the Supplier Diversity Program whether the certification/verification is pending or completed. Third-party challenges must comply with all the following: (1) be in writing and sent to the Clearinghouse; (2) set forth with specificity the grounds for the challenge in ordinary and concise language; (3) include the name and address of the third-party; and (4) be served on the affected applicant or eligible suppler on the same day sent to theClearinghouse. Such challenges may include supporting documentation.

7.3.1. The Clearinghouse will review third-party challenges to determine whether a factual basis for the questioning exists. If the Clearinghouse determines insufficient factual basis for the challenge exists, it shall act as follows: (a) inform the third-party and subject applicant or eligible supplier of this determination in writing within 20 business days of the receipt of the challenge and (b) inform the third-party of the right to file a Notice of Appeal to the Commission. Resolution ALJ-377(or successor rules) sets forth the process for filing the Notice of Appeal. Additional procedures related to Notices of Appeal are set forth herein.

7.3.2. If the Clearinghouse determines that sufficient factual basis for the challenge exists, the Clearinghouse shall require the applicant/eligible supplier to provide the Clearinghouse with any additional information needed to permit further evaluation of the verification/certification of the applicant/eligible supplier. Following the Clearinghouse's review and evaluation of the information presented by both the third-party and the applicant/eligible supplier, the Clearinghouse will propose a resolution and ~~a~~ provide for an opportunity to respond to the Clearinghouse's proposed resolution. Then, the Clearinghouse shall notify the third-party and the applicant or eligible supplier of its final verification decision and of the right to file a Notice of Appeal of this determination with the Commission pursuant to Resolution ALJ-377 (or successor rules) and the processes set forth herein.[3]

[3]

7.3.3. During the pendency of a third-party challenge of a business enterprise already verified/certified by the Clearinghouse, the business enterprise will remain certified/verified.

7.3.4. If a third-party challenge does not include the minimum criteria set forth above or it withdraws its challenge, the Clearinghouse may continue its review to determine whether the challenge merits consideration.

7.4. Contract Disputes. Disputes regarding general contract-related matters, such as failure to win a contract award, must be brought before the appropriate court or other forum. The Commission's jurisdiction on contract related matters is limited. Some disputes or complaints regarding the Commission's GO 156 Supplier Diversity Program, such as complaints about non-compliance with GO 156, may fall under the complaint process set forth in the Commission's Rules of Practice and Procedure. The Notice of Appeal, described herein, is also available.

8. PROCUREMENT GOALS FOR UTILITIES AND OTHER COVERED ENTITIES

Each utility and other covered entity shall set substantial and verifiable short-term (one year), mid-term (three years), and long-term (five years) goals for the utilization of eligible suppliers under the Commission's Supplier Diversity Program. Goals shall be set annually for each major product and service category which provides opportunities for procurement. "Substantial and verifiable Goals" mean goals which are realistic and clearly demonstrate a commitment to encourage the participation of eligible suppliers~~.~~ in contracts. Section 8 does not apply to community choice aggregators.

8.1. The utilities and other covered entities shall consider the following factors in setting goals:

8.1.1. Total utility or other covered entity purchasing and/or contracting projections;

8.1.2. Availability of eligible suppliers under the Commission's Supplier Diversity Program and competitiveness in the geographical area served by the utility or other covered entity;

8.1.3. Market dynamics based on historical data and trends; and

8.1.4. Other appropriate factors which may increase the share of business for eligible suppliers under the Commission's Supplier Diversity Program.

8.2. Each utility or other covered entity shall establish minimum long-term procurement goals for each major category of products and services purchased from eligible suppliers of not less than the following: 15% for minority business enterprises; 5% for women business enterprises; 1.5% for disabled veteran business enterprises; and 0.5% for 2022, 1.0% for 2023, and 1.5% for 2024 and beyond for LGBT business enterprises. No procurement goal has been adopted for persons with disabilities business enterprises.

Contracts or purchases with eligible suppliers under the Commission's Supplier Diversity Program may only count toward one procurement goal. For example, a minority and women business enterprises may be counted toward one goal, either the minority business enterprise goal or the women business enterprise goal but not both.

8.3. The specification of initial long-term procurement goals shall not prevent the utilities or other covered entities from seeking to reach parity with those public agencies and other companies, which the Legislature states in Pub. Util. Code § 8281(b)(1)(B) are awarding 30% or more of their contracts to women, minority, disabled veteran, and LGBT business enterprises.

8.4. Procurement goals shall also be established for both minority women business enterprises and non-minority women business enterprises. These goals are intended to ensure that utilities and other covered entities do not direct procurement programs toward non-minority women business enterprises and minority men business enterprises to the detriment or exclusion of minority women business enterprises.

8.5. Procurement goals shall be set for each major category of products or services. Goals need not be set for products or services which fall within an "excluded category" pursuant to former Section 8.5.[5]

8.6. For each major category of products and services where the minimum long-termprocurement goals required by Section 8.2 are not met, the utility or other covered entity shall include a comprehensive discussion of all efforts made to find or recruit eligible suppliers of products or services. The utility and other covered entity may also explain in detail in its annual report how its ability to meet its procurement goals are affected because eligible suppliers capable of supplying certain products and services are unavailable or because sole source procurement is the only available procurement method. As part of this explanation, the utility and other covered entity may also include data with exclusions pursuant to former Section 8.5~~.~~[6] ~~I~~if such data is necessary to more fully explain why it has not been able to eliminate exclusions, provided that the utility or other covered entities report must contain the data without exclusions in the first sentence.

8.7. A utility or other covered entity which is presently purchasing products or services from affiliates may subtract the dollars paid to affiliates for these products or services from the total dollars used as the basis for establishing procurement goals for purchases from eligible suppliers of these categories of products or services, provided that the utility or other covered entity encourages the affiliate to establish an appropriate subcontracting program where such affiliate employs subcontractors. Any utility or other covered entity which takes advantage of this section must in its annual report to the Commission state whether the affiliates have established a subcontracting program and describe the results of any such program. The utility or other covered entities annual plan must describe any future plans to encourage such a sub-contracting program. This section applies only to those utilities which are purchasing products or services from affiliates as of the effective date of the General Order adopted on May 30, 1988.

8.8. Procurement goals for each specific product or service category shall be expressed as a percentage of total dollars awarded by a utility and other covered entity to outside suppliers in that category; however, where appropriate, non-numeric goals may also be included.

8.9. Overall program procurement goals shall be expressed as a percentage of total dollars awarded to outside suppliers in all categories of products and services purchased by a utility or other covered entity other than products and services which are included in a fuel procurement base established pursuant to Section 8.11.

8.10. Payments to other utilities and franchise tax fees, other taxes and postage need not be included in the standard procurement base used to establish procurement goals.

---

[5] In D.03-11-024, the Commission revised GO 156 and modified Section 8.7. Prior to D.03-11-024, Section 8.5 provided:
A utility may create an" excluded category" of products or services where it is clearly evident that WMDVBEs do not provide a specific product or service, or that sole source procurement is the only available procurement method. The utility shall bear the burden of demonstrating the unavailability of WMDVBEs capable of supplying such products or services. Because there may in the future be WMDVBEs capable of supplying products or services in an excluded category, the utility must justify in its annual report the continued existence of is excluded category. Excluded categories must be noted in the utility's annual report to the Commission on WMDVBE program progress and future plans.

[6] *See supra.*

8.11. Each utility and other covered entity may establish a separate fuel procurement base for reporting progress and establishing goals for procurement of fuels from eligible suppliers under the Commission's Supplier Diversity Program. Utilities or other covered entities choosing to report fuel purchases separately from the purchase of other products and services must follow the guidelines set forth below:

8.11.1. Fuel used to power vehicles, heat utility facilities, and supply emergency generators may not be included in the fuel procurement base. Such fuel mustbe included in the standard procurement base used to establish goals, unlessthe fuel is purchased from another utility and thus subject to the exclusion authorized herein;

8.11.2. The fuel procurement base must, at a minimum, include all purchases of natural gas from domestic on-shore natural gas markets;

8.11.3. A utility or other covered entity which purchases eligible supplier's fuels other than domestic onshore natural gas must include such purchases in the fuel procurement base because Section 8.7 of this amended General Order does not permit utilities or other covered entities to exclude product and services categories for which there are available eligible suppliers; and

8.11.4. A utility or other covered entity may exclude purchases of fuel other than domestic onshore natural gas if such fuel qualifies for an exclusion under former Section 8.5 and if the utility or other covered entity plans for and reports on progress in increasing the procurement of such fuels from eligible suppliers.

8.12. Each utility and other covered entity shall make special efforts to increase utilization and encourage entry into the marketplace of eligible suppliers inproduct or service categories where there has been low utilization of eligiblesuppliers, such as legal and financial services, fuel procurement, and areasthat are considered technical.

8.13. No penalty shall be imposed for failure of any utility or other covered entity to meet or exceed procurement goals.

8.14. Utilities and other covered entities shall report their procurement goals in their annual plans.

9. REQUIRED ANNUAL REPORTS

Utilities, ~~and~~ other covered entities, and community choice aggregators shall provide an electronic copy of their Annual Report to the Commission's Executive Director on or before March 1 of each year. TheAnnual Report must provide details on ~~t~~ the utilities' ~~or~~ , other covered entities', or community choice aggregators' programs created to comply with the Commission's Supplier Diversity Program. Section 9 does not apply to utilities and electric service providers with gross annualCalifornia revenues between $15 million and $25 million, or community choice aggregators with gross annual revenues of $15 million or less.

9.1. The Annual Report shall contain at least the following elements:

9.1.1. A description of program activities engaged in during the previous calendar year. This description shall include both internal and external activities, and include the approximate amount of funding, to the extent available, directly expended on development and distribution of technical assistance to small and diverse businesses.

9.1.2. A summary of purchases and/or contracts, with breakdowns by ethnicity, product and service categories compared with total contract dollars awarded to outside suppliers in those categories, and with information regarding the total number of contracts, and the dollars awarded to eligible suppliers under the Commission's Supplier Diversity Program_. Each utility, ~~or~~ other covered entity, or community choice aggregator shall report the number of ~~from~~ eligible suppliers under the Commission's Supplier Diversity Program who have the majority of their workforce working in California, to the extent such information is readily accessible. Each utility, ~~or~~ other covered entity, or community choice aggregator shall also report the number of ~~from~~ eligible suppliers under the Commission's Supplier Diversity Program that received direct spendduring the reporting year.

9.1.3. An itemization of program expenses provided in the format approved by Commission staff, as guided by Attachment A to D.95-12-045, D.15-06-007, and other relevant decisions.

9.1.4. Utilities and other covered entities shall provide a ~~A~~ description of progress in meeting or exceeding set procurement goals andan explanation of any circumstances that may have resulted in not meeting those goals. This subsection 9.1.4 does not apply to community choice aggregators.

9.1.5. A summary of prime contractor utilization of eligible subcontractors suppliers under the Commission's Supplier Diversity Program.

9.1.6. A list of complaints received from eligible suppliers in the past year, accompanied by a brief description of the nature of each complaint and its resolution or current status. For purposes of this subsection, a *complaint* means any written or verbal statement from an eligible supplier or third-party that the utility's, ~~or~~ other covered entity's, or community choice aggregator's program is unsatisfactory or unacceptable.

9.1.7. Utilities and other covered entities shall provide a~~A~~ description of any efforts made to recruit eligible suppliers for products orservices in procurement categories where utilization has been low, such as legal and financial services, fuel procurement, and areas that are considered technical. This subsection 9.1.7 does not apply to community choice aggregators.

9.1.8. Utilities, ~~and~~ other covered entities, and community choice aggregators shall retain all documents and data they rely on in preparing their annual reports for the longer of either three years orin conformance with the document retention policies of the utility, ~~or~~ other coveredentity, or community choice aggregator. The utility, ~~or~~ other covered entity, or community choice aggregator shall provide these documents and data to the Commission, upon request.

9.1.9. Utilities, ~~and~~ other covered entities, and community choice aggregators shall summarize purchases and/or contracts from eligible suppliers under the Commission's Supplier Diversity Program in product and service categories that include energy storage systems, vegetation management, renewable and non-renewable energy, wireless communications, broadband, smart grid, rail projects and electronicprocurement, in addition to their current reporting categories. Utilities, other covered entities, and community choice aggregators have discretion to segregate overlapped dollars. Utilities, ~~and~~ other covered entities, and community choice aggregators shall report renewable and nonrenewable energy procurement in a manner similar to their reporting of fuel procurement.

9.1.10. The Commission's staff may conduct as many audits of utilities, ~~and~~ other covered entities, and community choice aggregators as it deems necessary but shall audit at least one annual GO156 report randomly selected every two years from a different utility industry to confirm that the reported spend is accurate. The Commission's staff may determine the selection process for this random selection and the audit methodology. The Commission's staff may conduct audits of any reports or data provided to the Commission by utilities, ~~and~~ other covered entities, and community choice aggregators regarding their participation in the Supplier Diversity Program.

9.1.11. Each utility, ~~or~~ other covered entity, or community choice aggregator which elects to report fuel procurement separately must file with the Commission's Executive Director on or before March 1 of each year a separate detailed and verifiable report on participationin fuel markets by eligible suppliers under the Commission's Supplier Diversity Program. These reports must include, at a minimum, the results of purchases in each fuel category.

(a) Each utility, ~~or~~ other covered entity, or community choice aggregator shall report purchases by:

(1) Market origin and fuel type;

(2) Volume and dollar magnitude;

(3) Term of sale, e.g., spot, intermediate, long term; and

(4) Ethnicity and gender of the supplier.

(b) Each utility, ~~and~~ other covered entity, and community choice aggregator shall provide, to the extent applicable:

(1) An explanation of how existing and/or changing market conditions are affecting the utility's or other covered entity's ability to meet or exceed its procurement goals for fuel (this subsection (b)(1) does not apply to community choice aggregators as Proposition 209 prohibits such procurement goals for community choice aggregators);

(2) A comprehensive description of the specific out-reach programs used to seek eligible suppler fuel suppliers in each market in which fuel is purchased (this subsection (b)(2) does not apply to community choice aggregators as Proposition 209 prohibits such recruitment by community choice aggregators); and

(3) A justification for any exclusion of a specific fuel category from the utility's, ~~or~~ other covered entity's, or community choice aggregator's fuel procurementbase.

9.2. This General Order is not intended to permit erosion of programs and reporting presently engaged in by a utility, other covered entity, or community choice aggregator.

9.3. Nothing in this General Order shall prohibit any utility, ~~or~~ other covered entity, or community choice aggregator from breaking down specific categories further than presently required (for example, reporting contracts awarded to Filipino Americans separately from those awarded toAsian Pacific Americans, or reporting male and female results within minority business enterprise classifications).

10. REQUIRED ANNUAL PLANS

Utilities, ~~and~~ other covered entities, and community choice aggregator shall provide an electronic copy of ~~its~~their Annual Plan~~on~~to the Commission's Executive Director on or before March 1 of each year. Pursuant to Pub. Util. Code § 8283(a) and Section 10.1 below, the Annual Plan of utilities and other covered entities with gross annual California revenues exceeding $25 million shall~~, that~~ include~~s~~ a detailed and verifiable plan for encouraging procurement in all categories of eligible business enterprises under the Commission's Supplier Diversity Program. This Section 10 does not apply to utilities and ~~electric service providers~~other covered entities with gross annual California revenues between $15 million and $25 million~~.~~ Pursuant to Pub. Util. Code § 366.2(m)(1) and section 10.2 below, the Annual Plan of community choice aggregators shall include a detailed and verifiable plan for increasing procurement from small, local, and diverse business enterprises in all categories, including, but not limited to, renewable energy, energy storage system, and smart grid projects.

10.1. Utilities and Other Covered Entities. The Annual Plan of utilities and other covered entities shall contain at least the following elements:

10.1.1. Short, mid, and long term procurement goals, as required by Section 8*, herein;*

10.1.2. A description of its program activities planned for the next calendar year. This description shall include both internal and external activities;

10.1.3. A plan for recruiting eligible suppliers of those products or services where utilization has been low, such as legal and financial services, fuel procurement, and areas that are considered technical.

10.1.4. A plan for seeking and or cultivating eligible suppliers of those products and services where eligible suppliers are currently unavailable.

10.1.5. A plan for encouraging both prime contractors and grantees to engage eligible suppliers in subcontracts in all categories which provide subcontracting opportunities.

10.1.6. A plan for complying with the program guidelines established by the Commission, as required by Pub. Util. Code § 8283(c). The Executive Director's Office will be responsible for developing, periodically refining, and recommending such guidelines for the Commission's adoption in an appropriate procedural forum.

10.2. Community Choice Aggregators. The Annual Plan of community choice aggregators shall contain at least the following elements:

10.2.1. Description of program activities to increase community choice aggregator procurement related to small, local, and diverse business enterprises planned for the next year in all categories, including, but not limited to, renewable energy, energy storage systems, and smart grid projects.

11. ANNUAL REPORTS AND PLANS FOR COMMUNITY CHOICE AGGREGATORS~~Annual Reports and Annual Plans for Community Choice Aggregators~~:

As set forth in R.21-03-010, community choice aggregators shall comply with similar ~~the same~~ reporting requirements as utilities and other covered entities except that the reporting requirements may be modified to reflect the prohibitions set forth in Proposition 209, as well as the fact that, at this time, energy procurement represents the majority of expenses for a typical community choice aggregator. Staff will develop alternative reporting requirements ~~more limited than~~to those applicable to utilities and other covered entities, but which still includethe information applicable to community choice aggregators as set forth in Section 9 and Section 10, herein. Staff will meet with community choice aggregators and stakeholders ~~on consider~~ to develop revisions to the reporting requirements, as needed. Staff will provide a copy of any revised reporting requirements to community choice aggregators, stakeholders, and the service list of this proceeding (or successor proceeding related to GO 156). These reporting requirements must continue to promote the state policy of increasing contracts (to the extent not prohibited by Proposition 209) between community choice aggregators and (1) eligible suppliers, and (2) small, local and diverse business enterprises.

12. Annual Forms for Smaller Utilities and Smaller Electric Service Providers

Pursuant to Pub. Util. Code § 8283(f), this section sets forth the rules that apply to smaller utilities and electric service providers, i.e., those with gross annual California revenues between $15 million and $25 million. These smaller other covered entities shall annually, on or before March 1, electronically submit a "simplified form" to the Commission's Executive Director. The information to be included in the form shall be developed by the Commission's staff together with these other covered entities, as set forth in Rulemaking 21-03-010. The Commission's staff will provide a copy of this simplified form via email to the service list of Rulemaking 21-03-010 (or the successorproceeding). The reporting requirements in Section 9 and Section 10 do not apply to these smaller other covered entities.

13. COMMISSION ANNUAL REPORT TO THE LEGISLATURE

As required by Pub. Util. Code § 8283(e), the Commission shall provide an annual report to the Legislature beginning January 1989 on the progress of activities undertaken by each utility, ~~or~~ other covered entity, and community choice aggregator to implement Pub. Util. Code §366.2 and §§8281 through 8286 and this General Order.

13.1. In this annual report, the Commission shall recommend a program for carrying out the policy declared in the above-mentioned sections of the Pub. Util. Code, together with recommendations for any legislation it deems necessary or desirable to further that policy.

13.2. This annual report shall include recommendations to the utilities, ~~and~~ othercovered entities, and community choice aggregators for the achievement of maximum results in implementing legislative policy and this General Order.

13.3. This annual report shall include information initially identified in Resolution Exec-001, which provides for monitoring and evaluation of the Supplier Clearinghouse "on a periodic basis." As part of this monitoring and evaluation of the Supplier Clearinghouse, the Commission's Annual Report to the Legislature will include an analysis of the existing contract between Supplier Clearinghouse and the utilities (e.g., audits of revenues and expenditures associated with the certification program).

14. WORKFORCE DIVERSITY AND BOARD DIVERSITY REPORTING

All utilities and other covered entities shall include information regarding workforce diversity and board diversity in annual reports, starting March 2024. The Commission's staff will implement this mandatory reporting requirement. The Commission's staff will provide the mandatory reporting requirements to the service list of R.21-03-010 (or successor proceeding) and place the requirements on the Commission's webpage for GO 156. To the extent practicable and permitted by law, community choice aggregators may provide information regarding workforce diversity and board diversity in annual reports, starting March 2024.

15. VOLUNTARY COMPLIANCE AND REPORTING

The Commission supports all efforts to voluntarily comply with the state policy of increasing procurement from diverse suppliers set forth in Pub. Util. Code §§ 8281-8286.

Pub. Util. Code § 366.2(m)(3) encourages community choice aggregators with gross annual revenues under $15 million to adopt a plan for increasing procurement from small, local, and diverse business enterprises in all categories.

Pub. Util. Code § 8283(e)(1) encourages certain small utilities and electric service providers, i.e., those with gross annual California revenues under $15 million, to adopt a plan for increasing women, minority, disabled veteran, and LGBT business enterprise procurement.

Pub. Util. Code § 8283(e)(2) encourages exempt wholesale generators, distributed energy resource contractors, and energy storage system companies to adopt a plan for increasing women, minority, disabled veteran, and LGBT business enterprise procurement and to voluntarily report activity in this area to the Legislature on an annual basis. Cable television corporations and direct broadcast satellite providers were previously included in Pub. Util. Code § 8283(e)(2).

16. COMMISSION ANNUAL *EN BANC* MEETING

The Commission shall hold an annual *en banc* hearing or other proceeding to provide all stakeholders, such as utilities, other covered entities, community choice aggregators, members of the public, community-based organizations, and eligible suppliers under the Commission's Supplier Diversity Program the opportunity to share ideas and make recommendations for effectively implementing legislative policy under Pub. Util. Code §366.2 and §§ 8281 through 8286 and this General Order. The Commission's staff shall provide notice of the annual *en banc* broadly, including to the service list for the most recent proceeding pertaining to General Order 156 and any service lists pertaining to related topics.

Approved and dated______________, at San Francisco, California.

PUBLIC UTILITIES COMMISSION STATE OF CALIFORNIA

By_____________*Executive Director*

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.21-10-002

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ON PHASE 1 OF THE IMPLEMENTATION TRACK: MODIFICATIONS TO THE CENTRAL PROCUREMENT ENTITY STRUCTURE

Evelyn Kahl
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94520
(415) 254-5454
regulatory@cal-cca.org

March 2, 2022

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page

California Public Utilities Commission Decisions

California Public Utilities Commision Proceedings

California Public Utilities Commission Rules of Practice and Procedure

SUMMARY OF ERRORS AND RECOMMENDATIONS

- The PD fails to allow sufficient time for both CPEs and LSEs to conduct procurement;
    - CPE procurement for 2023 must be completed by June 2022;
    - CPE procurement for 2024 and beyond must be completed by late September or early October one year prior to the year-ahead showing;
- The PD provides insufficient justification for omitting a limited system and flexible RA waiver process for RA compliance year 2023 if CPE shortfalls are not filled by the end of June 2022;
- The PD fails to promote self-showing of local resources because the incentives and disincentives to self-show are not balanced;
    - The PD correctly modifies self-showing requirements to require an attestation rather than a contract between the self-showing LSE and the CPE;
    - The PD exacerbates disincentives to self-show by placing the risk of CAISO backstop costs on the self-showing entity;
    - The PD must be modified to confirm that the replacement obligation for self-shown resources belongs to the CPE;
- A new Ordering Paragraph should be added requiring a holistic review of the CPE framework in Phase Three of R.21-10-002.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.21-10-002

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION ON PHASE 1 OF THE IMPLEMENTATION TRACK: MODIFICATIONS TO THE CENTRAL PROCUREMENT ENTITY STRUCTURE

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision on Phase 1 of the Implementation Track: Modifications to the Central Procurement Entity Structure* (Proposed Decision or PD) issued on February 10, 2022.

I. INTRODUCTION

Decision (D.) 20-06-002 adopted a "hybrid" central procurement entity (CPE) framework for local Resource Adequacy (RA) in Pacific Gas and Electric Company (PG&E) and Southern California Edison Company's (SCE) service areas beginning with the 2023 RA compliance year.[2]

---

[1] California Community Choice Association represents the interests of 23 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] *Decision on Central Procurement of the Resource Adequacy Program*, June 11, 2020 (R.17-09-020) (D.20-06-002).

Under this framework, load-serving entities (LSEs) in PG&E and SCE's territories no longer receive local RA allocations. Instead, the CPE is required to meet the local RA obligations through its own procurement. LSEs or generators may sell bundled local RA to the CPE or LSEs may reduce the overall CPE procurement requirement by self-showing local RA attributes to the CPE, while retaining the system and flexible attributes of the resource for their own use. The CPE can also defer procurement to the California Independent System Operator's (CAISO's) backstop mechanisms if procurement costs are deemed unreasonably high.

On November 1, 2021, PG&E and SCE's CPEs submitted Annual Compliance Reports summarizing CPE procurement activity in 2021. SCE Advice Letter 4626-E, dated November 1, 2021, indicated a small amount of unfulfilled monthly 2023 obligations likely to be filled in future request for offers (RFOs), and therefore, nothing has been deferred to the CAISO's backstop processes.[3] PG&E's Supplemental CPE Annual Compliance Report filed on November 19, 2021 indicated procurement for 2023 is short of the local RA requirement by up to roughly 6,000 MW, or 53 percent of its requirement.[4] It is not clear in the Supplemental CPE Annual Compliance Report if the CPE will attempt to do more procurement to meet the local obligation or defer procurement to the CAISO's Capacity Procurement Mechanism (CPM) authority.

Given the significant short position, LSEs have a high level of uncertainty about the amount of Cost Allocation Mechanism (CAM)-allocated resource credits they can expect to receive, significantly complicating their 2023 system and flexible procurement. The timeline adopted in the PD exacerbates this uncertainty by prolonging the allocation of system and flexible credits to 6 to 8 weeks prior to the year-ahead showings. The PD makes an improvement to the self-showing process by allowing attestations to self-show rather than requiring contracts between the self-showing entity

---

[3] *Central Procurement Entity Annual Compliance Report: 2021*, Southern California Edison Company (SCE), Nov. 1, 2021, Independent Evaluator Report at 31 (document page 70 of 98).

[4] *Supplemental: Pacific Gas and Electric Company ("PG&E") Central Procurement Entity ("CPE") Annual Compliance Report*, Nov.19, 2021, Attachment 1.

and the CPE. However, the imbalance between the incentives and disincentives to self-show is not resolved by this change alone. In fact, the PD makes other modifications that would worsen this imbalance by placing additional risks on self-showing LSEs.

CalCCA makes the following necessary recommendations to the Commission that must be adopted to enable a functioning CPE framework:

- The PD fails to allow sufficient time for both CPEs and LSEs to conduct procurement;
  - CPE procurement for 2023 must be completed by June 2022;
  - CPE procurement for 2024 and beyond must be completed by late September or early October one year prior to the year-ahead showing;
- The PD provides insufficient justification for omitting a limited system and flexible RA waiver process for RA compliance year 2023 if CPE shortfalls are not filled by the end of June 2022;
- The PD fails to promote self-showing of local resources because the incentives and disincentives to self-show are not balanced;
  - The PD correctly modifies self-showing requirements to require an attestation rather than a contract between the self-showing LSE and the CPE;
  - The PD exacerbates disincentives to self-show by placing the risk of CAISO backstop costs on the self-showing entity;
  - The PD must be modified to confirm that the replacement obligation for self-shown resources belongs to the CPE; and
- A new Ordering Paragraph (OP) should be added requiring a holistic review of the CPE framework in Phase Three of R.21-10-002.

II. THE PD FAILS TO ALLOW SUFFICIENT TIME FOR BOTH CPES AND LSES TO CONDUCT PROCUREMENT

A. CPE Procurement for 2023 Must be Completed by June 2022

The timeline adopted in D.20-06-002 specified that, in late September to early October 2021, LSEs would receive final CAM credits (based on coincident peak-load shares) for any system and flexible capacity that was procured by the CPE.[5] This would have allowed roughly

---

[5] PD at 26.

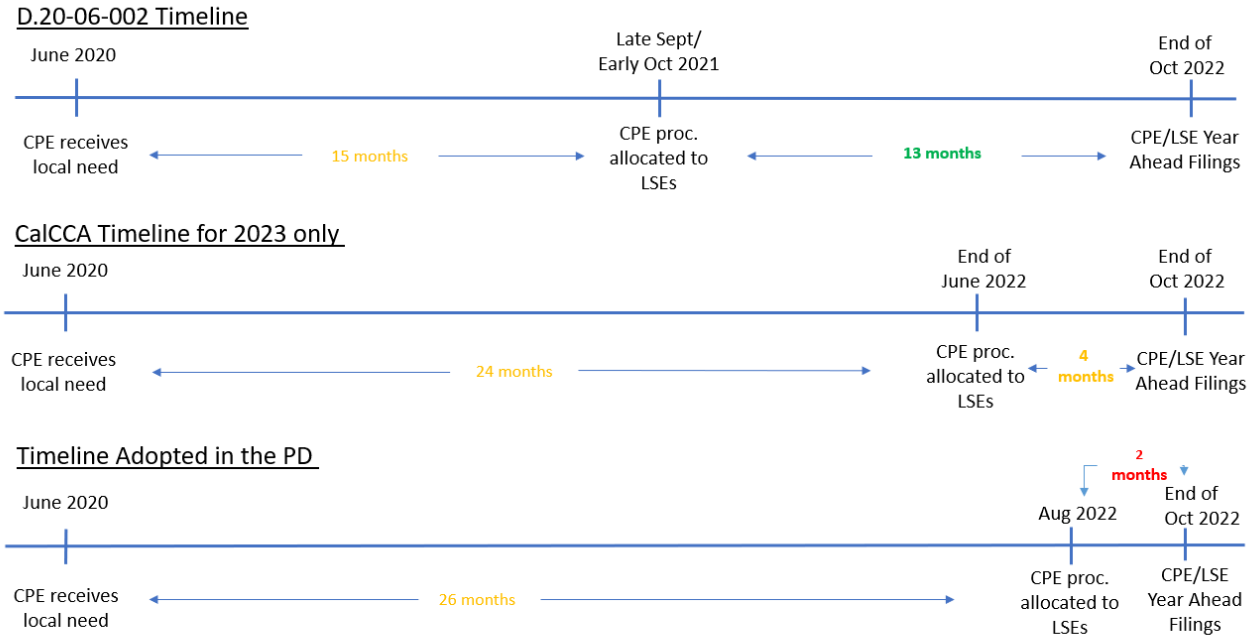
15 months from the time the CPE is allocated its local requirement in June 2020 and the time CPE procurement would need to conclude to allocate credits to LSEs. Then, LSEs would have roughly 13 months from the time they receive their credits from CPE procurement in late September or early October 2021 and LSEs' year-ahead showings for the 2023 compliance year made in late October 2022. This timeline appropriately balances the time provided for CPE procurement of local RA and LSE procurement of system and flexible RA.

The PD incorrectly concludes PG&E's proposal modifying the CPE timeline gives both LSEs and CPEs a similar amount of time to complete necessary procurement after receiving allocations.[6] Under the PD, the time between LSEs receiving credits from the CPE and their year-ahead showings is reduced from 13 months to 2 months at most. Leaving LSEs uncertain of the amount of their system and flexible credits until 6 to 8 weeks prior to their year-ahead showings is unworkably late.

The following figure demonstrates that the PD significantly disadvantages LSEs in their system RA procurement by modifying the timeline adopted in D.20-06-002. Specifically, the PD fails to recognize that the three-year forward local RA program provides CPEs the ability to complete their procurement roughly one year prior to the year-ahead filings, subject to any changes in the local capacity requirements (LCR) in subsequent years. This encroaches on LSEs' ability to procure their own system and flexible RA after receiving CPE credits.

[6] PD Finding of Fact 8.

Figure 1: CPE Timeline Adopted in D.20-06-002 Compared to CalCCA's Proposed Timeline for 2023 and the Timeline Adopted in the PD



Parties in this proceeding have incorrectly suggested LSEs can mitigate against the uncertainty introduced by this change by self-showing resources to the CPE. First, LSEs are under no obligation to self-show and, as described in Section IV, under the current framework it may be in their best interest not to self-show. Second, while LSEs retain the system and flexible attributes of self-shown resources, they do not receive megawatts (MW) for MW allocation of the local attributes. Therefore, even if an individual LSE self-shows all their resources to the CPE, the LSE is still uncertain of what it will be allocated because its allocation depends on what other LSEs elect to self-show. For example, if total LSE self-showings cover the entire CPE obligation, the CPE will not need to undertake its own procurement, LSEs will not be allocated any credits from the CPE, and LSEs will need to meet their system and flexible requirement using their own resources. On the other extreme, if no LSEs self-show, the CPE will need to procure to the total requirement, LSEs will be allocated system and flexible credits for the CPE's procurement, and LSE procurement for their own obligations would be significantly reduced.

Individual LSEs cannot predict the amount of credits they will receive until procurement is complete because the amount of credits depends on the amount of self-showing done by other LSEs and the amount of procurement completed by the CPE.

The Commission should revise the PD to require CPEs to finalize procurement by the end of June 2022, such that credits from CPE procurement can be allocated to LSEs at the same time the system and flexible requirements are adopted. While the PD aims to provide CPEs and LSEs similar amounts of time to conduct procurement, the PD fails to recognize that the three-year forward local RA program and the timeline adopted in D.20-06-002 already provided CPEs and LSEs roughly the same amount of time to conduct procurement (roughly 15 months and 13 months, respectively).

Parties opposed to CalCCA's proposal suggest that requiring CPE procurement to conclude by the end of June 2022 would constrain efficient procurement by the CPE and that because local RA requirements are not finalized until June each year, CPEs would be uncertain of their final local requirement.[7] While the local requirements may change from when they are initially adopted three years forward to when they are finalized one year forward, they are unlikely to change with the same magnitude as the largest CPE short position observed for 2023. From 2020 to 2021, the largest change in the LCR was roughly 1,800 MW due to changes in the LCR study criteria, which would not likely be a common recurrence. From 2021 to 2022, the largest change in the LCR was roughly 880 MW due to load forecast increases. Because the CAISO establishes local RA requirements on a three-year forward basis, most marginal changes to the local requirement should be minimal year over year. Notably, the changes experienced in

[7] PD at 31.

LCR requirement changes have been significantly lower than the roughly 6,000 MW CPE open position that impact LSE system and flexible procurement.

B. CPE Procurement for 2024 and beyond must be Completed by Late September or Early October One Year Prior to the Year Ahead Showing

CalCCA proposed CPEs finalize their procurement for compliance year 2023 by June 2022.[8] This proposal was made in recognition of the significant shortfall in CPE procurement for 2023 and to allow CPEs to fill their short positions prior to allocating system and flexible credits to LSEs. For compliance years 2024 and beyond, however, the Commission must commit to giving LSEs adequate time between receiving their system and flexible allocations from the CPEs and submitting their year-ahead filings. This can be accomplished by requiring CPE procurement to be completed in late September or early October one year prior to the yearly showings for RA compliance years 2024 and beyond, as originally established in D.20-06-002. If the local requirements change between the adoption of the three-year forward and one-year forward LCRs, the CPE should be able to conduct procurement to fill the marginal need.

This timeline is critical because LSEs must have certainty around their system and flexible obligations in order to perform orderly and efficient procurement. Extending CPE procurement beyond this timeframe could result in increased ratepayer costs because LSEs may procure above what they need given the uncertainty around the amount of credits they can expect to receive. Further, when CPEs are still procuring at the same time as the LSEs, the CPE and LSEs will be seeking to procure the same MW in the market, driving up costs for all parties. Once final allocations are known, all LSEs will need to execute deals with suppliers that are likely bidding into multiple solicitations under the same minimal timeframe. A timeline that

---

8 *California Community Choice Association's Phase 1 Proposals in Response to the Assigned Commissioner's Scoping Memo and Ruling*, Dec. 13, 2021 (R.21-10-002) (CalCCA Proposals) at 8-9.

allows CPEs to complete their procurement of local RA, then LSEs to complete their procurement of system RA after receiving credits from the CPE will result in the most orderly and efficient outcome because each entity will know the amount of their obligation and have sufficient time to conduct procurement.

III. THE PD PROVIDES INSUFFICIENT JUSTIFICATION FOR OMITTING A LIMITED SYSTEM AND FLEXIBLE RA WAIVER PROCESS FOR RA COMPLIANCE YEAR 2023 IF CPE SHORTFALLS ARE NOT FILLED BY THE END OF JUNE 2022

At this time, it remains unclear if the CPE will be able to meet its full procurement obligation for 2023. This uncertainty has already significantly impacted LSEs in the process of conducting procurement of system and flexible RA to meet their own requirements. If the CPE does not meet its full local RA obligation by the end of June 2022, when system and local requirements are finalized, the Commission should adopt a system and flexible RA waiver for the 2023 RA compliance year for LSEs whose procurement was impacted by CPE procurement shortfalls as CalCCA proposed.[9] CalCCA's proposed waiver would be limited to the 2023 compliance year and only apply to LSE deficiencies up to the MW amount of expected CPE allocations had the CPE fully met its procurement requirement.

By omitting a discussion on CalCCA's proposed limited system and flexible waiver process resulting from unfilled CPE procurement, the PD would "triple down" on financial penalties LSEs face as a direct result of procurement that should have been completed on their behalf but was not. LSEs face financial penalties for failing to meet their requirements through both the Commission penalty structure and potential CAISO backstop costs. Additionally, the Commission's penalty structure includes a tiered point system that assigns points to LSEs each time they are deficient, resulting in higher penalties the more points accrued. If the Commission

---

9 CalCCA Proposals at 14.

will not institute system and flexible RA waivers for this limited instance, the Commission must, at minimum, not assign any points to LSEs with deficiencies within the amount of CPE credits they did not receive. This is appropriate under the current situation where LSEs are still unclear about the system and flexible RA credits they can expect to receive. The CPE does not face RA penalties for deferring procurement to CAISO's backstop authority. LSEs, on the other hand, face penalties of up to $26.64/kW- month under the tiered penalty structure adopted in D.21-06-029.[10] If a waiver is not adopted, the Commission should not assign points to LSEs who are short of their obligation by the amount of credits they could have received from the CPE had the CPE fully met its obligation but did not.

IV. THE PD FAILS TO PROMOTE SELF-SHOWING OF LOCAL RESOURCES BECAUSE THE INCENTIVES AND DISINCENTIVES TO SELF-SHOW ARE NOT BALANCED

A. The PD Correctly Modifies Self-Showing Requirements to Require an Attestation Rather than a Contract Between the Self-Showing LSE and the CPE

The PD expresses concern that a limited amount of local resources were self-shown to the PG&E CPE and indicated that it is important to address and eliminate barriers that unnecessarily disincentivize LSEs from self-showing.[11] The PD removes one of the barriers to self-showing by adopting an attestation requirement to self-show in lieu of the rules adopted in D.20-12-006 that require self-showing LSEs to execute contracts with the CPE.[12] CalCCA supports this portion of the PD. The requirement to execute contracts between self-showing LSEs and CPEs, coupled with the CPE requiring LSEs to provide the same information outlined in the selection criteria established in D.20-06-002 put unnecessary risk on the LSE or required information about resource attributes

---

[10] *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program*, June 24, 2021 (R.19-11-009) at 55-60.

[11] PD at 13.

[12] PD at 17.

that LSEs did not have.[13] Adopting an attestation requirement will eliminate unnecessary barriers that may prevent LSEs from self-showing and will likely lead to more self-showing offers if the disincentives to self-show described below are appropriately addressed.

B. The PD Exacerbates Disincentives to Self-Show by Placing the Risk of CAISO Backstop Costs on the Self-Showing Entity

The proposal in the PD regarding CPM cost allocation creates further imbalances between the benefits and risks of self-showing that threaten the Commission's ability to maximize the amount of resources shown to the CPE. The PD further modifies the self-showing process, requiring all LSEs in the CPE service area to cover backstop costs if a CPM is caused by failure of a self-shown resource to perform due to a planned outage. The PD would also require all LSEs, not only the self-showing LSE, to cover backstop costs incurred due to a non-performing self-shown resource located outside of the CPE service area. However, if a self-shown resource inside the CPE service area fails to perform due to any reason other than a planned outage, the self-showing LSE would be responsible for any associated CPM costs. The PD adopts this proposal on the basis of ensuring self-shown resources are actually shown to the Commission and CAISO.

The PD also expresses the need to understand why LSEs may not self-show their resources and adopts a justification statement LSEs must submit explaining why they did not bid or self-show.[14] When comparing the risks and benefits to self-showing, however, it is clear a major explanation is likely that the incentives and disincentives are not aligned in a way that would encourage LSEs to self-show. This proposal must be modified to address this

13 D.20-06-002 Ordering Paragraph 14.
14 PD at 15.

misalignment if the Commission aims to address its concern around the small number of self-showing offers picked up by the CPEs for 2023.

The benefits of self-showing are 1) a small Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) payment and 2) a pro-rata reduction in CPE procurement costs. The LCR RCM was designed to incentivize the development of new preferred or energy storage resources in local areas. Because the LCR RCM only applies to new preferred or energy storage resources, most local resources are not eligible for compensation if self-shown.[15] Additionally, because system RA capacity is constrained, the premium for local RA, the basis of the LCR RCM payment, is very small. In some local areas, the LCR RCM is $0/kW-month. At most, the LCR RCM is $1.78/kW-month.[16]

When an LSE self-shows a local resource, it lowers the overall amount of the CPE local RA obligation. Therefore, while the self-showing LSE maintains all the system and flexible attributes, it only receives a reduction in CPE costs pro-rata based on its load share in the local area. For example, an LSE with a 3 percent load ratio share that shows a 100 MW resource would receive a reduction in cost allocation from the CPE of 3 MWs. However, in exchange for this reduction in cost allocation, under the PD the self-showing LSE takes on 100 percent of the CAISO CPM cost risk if the resource is unable to perform in a given month.

The PD would introduce additional risks to self-showing by assigning CAISO backstop costs to the self-showing LSE in the event a self-shown resource cannot perform for reasons other than a planned outage. If a resource is shown for system RA only, as opposed to local RA,

---

15 *Decision On Track 3.A Issues: Local Capacity Requirement Reduction Compensation Mechanism And Competitive Neutrality Rules*, Dec. 3, 2020 (D.20-12-006), Conclusion of Law 4 and OP 4.

16 See Local Capacity Requirement Reduction Compensation Mechanism: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/lcr-rcm-prices.pdf .

the resource can be replaced by another system resource if the shown resource becomes unavailable. However, if a resource is shown for local, the resource has a like-for-like replacement requirement, in which the resource must be replaced by another resource in the same local area. Because system RA is scarce and local RA is even more scarce, there is significant risk that the price of replacement capacity local premium will be higher than the LCR RCM, if replacement is available at all. Keeping in mind that the LSE will still be responsible for meeting their system and flexible RA obligations, the LSE will need to procure system and potentially flexible resources. In addition to this cost, if the LSE cannot find a local resource replacement, the self-showing LSE would be subject to the entirety of CAISO backstop costs with a soft-offer cap of $6.31/kW-month. The sum of the LSE procuring to meet system RA and the CAISO backstop costs will clearly be higher than the $1.78/kW-month maximum LCR RCM payment the self-showing LSE would receive. Taken together, the LCR RCM and pro-rata reduction in CPE costs will likely not be enough to outweigh the risks of self-showing via replacement or CPM costs as established in the PD.

C. The PD Must be Modified to Confirm that the Replacement Obligation for Self-Shown Resources Belongs to the CPE

The PD should be modified to require the CPE to allocate backstop costs pro-rata to all LSEs including the self-showing LSE, commensurate with the benefits received. This modification would eliminate the risk of self-showing present in the PD's proposal for the CPE to allocate the full backstop costs to self-showing LSEs who only receive a pro-rata share of the benefits. The PD must be modified such that the following steps are taken when a self-shown resource does not perform:

1. Allow, but do not require, self-showing LSEs to substitute non-performing self-shown resources with another resource as the like-for-like local resource;

2. If the self-showing LSE does not substitute, allow the CPE to replace the non-performing self-shown resources and allocate the costs to all LSEs in the TAC area, as all LSEs receive benefit from the self-shown resource or its replacement; and
3. If CAISO backstop is necessary, the CPE should allocate the CAISO backstop costs to all LSEs, as all LSEs receive the local benefit.

This approach will allow LSEs to self-show without taking on additional replacement or backstop risk beyond what it would have if it did not self-show. It also allows for replacement capacity to be provided when available, either by the self-showing LSE or the CPE, to avoid the need for the CAISO to exercise its backstop authority. The Commission should modify the PD's self-showing process in this way to align the risks and benefits to self-showing and, in turn, improve the likelihood LSEs will choose to self-show.

V. A NEW ORDERING PARAGRAPH SHOULD BE ADDED REQUIRING A HOLISTIC REVIEW OF THE CPE FRAMEWORK IN PHASE 3 OF R.21-10-002

D.20-06-002 stated, "The Commission will continue to evaluate and monitor the central procurement function in SCE and PG&E's TAC areas and remains open to designating a different CPE in future years. To that end, we authorize Energy Division to prepare a report assessing the effectiveness of the CPE structure by 2025."[17] Progress made on CPE procurement thus far has highlighted challenges with the hybrid framework adopted in D.20-06-022, revealing the Commission cannot wait until 2025 to assess the effectiveness of the CPE framework. The Commission must perform a comprehensive review of the CPE framework within Phase Three of the Implementation Track of R.21-10-002 to consider whether wholesale modifications to the CPE framework are warranted. CPE was designed in an environment in which local RA was constrained and system RA was not significantly constrained, leading to the assumption that local would be at a premium to system resources. With the changes in those assumptions, the

[17] D.20-06-002 at 35.

Commission should investigate whether the circumstances leading to the conclusion that CPE was necessary are still relevant.

In 2020, PG&E LSEs were 0 percent short of their total PG&E local RA obligations for all PG&E local areas.[18] For 2023, thus far, the PG&E CPE is short up to 53 percent of its local obligation for all local areas.[19] These numbers prompt the question: Is the current CPE framework an improvement over the former LSE-based obligation framework? The Commission should examine in Phase 3 whether the current scarcity of both system and local is better addressed by LSE-based procurement or by shifting the CPE framework to a residual model as contemplated by the parties in the CPE settlement that was ultimately rejected in favor of the hybrid structure.

VI. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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

March 2, 2022

[18] CPUC 2020 Resource Adequacy Report Table 5 at 20. Note that 2020 was the first year of disaggregating the PG&E "other" local areas into their component parts. While individual local areas were left unmet, experience from the 2020 local RA showings resulted in D.20-06-031 which allowed entities not meeting individual local areas to obtain a waiver if they had met the aggregated PG&E "other" local area needs.

[19] *Supplemental: Pacific Gas and Electric Company ("PG&E") Central Procurement Entity ("CPE") Annual Compliance Report*, Nov.19, 2021, Attachment 1.

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

FINDINGS OF FACT

8. The timeline adopted in D.20-06-002 strikes a reasonable balance between ~~PG&E's proposed CPE procurement timeline strikes a reasonable balance between~~ the need of LSEs to have sufficient time for RA portfolio planning and the need for the CPEs to have adequate time to complete an all-source solicitation. Given the shortfall in CPE procurement for RA year 2023, the CalCCA proposed timeline strikes a reasonable balance in allowing the CPE to fill its shortfall while also allowing time for LSEs to meet their system and flexible procurement obligations. ~~PG&E's proposal gives both LSEs and the CPEs a similar amount of time (6-8 weeks) to complete necessary procurement after receiving allocations.~~

CONCLUSIONS OF LAW

5. ~~PG&E's proposed CPE procurement timeline should be adopted to replace the timeline previously adopted in Ordering Paragraph 28 of D.20-06-002.~~ The CPE should complete 2023 procurement by the time system and flexible requirements are adopted in late June 2022. The timeline previously adopted in Ordering Paragraph 28 or D.20-06-002 should continue beginning for compliance year 2024.

ORDERING PARAGRAPHS

1. The following requirements are adopted for non-performance of self-shown local resources:

    a. Self-showing LSEs shall be allowed, but not required, to provide a substitute resource as the like-for-like local resource to replace non-performing self-shown resources.

    b. If the self-showing LSE does not substitute, CPE shall be allowed to replace the non-performing self-shown resources and allocate the costs to all LSEs in the TAC area.

    c. ~~a.~~ If the California Independent System Operator (CAISO) makes a local Capacity Procurement Mechanism (CPM) designation, the central procurement entity (CPE) shall be charged any associated CAISO backstop procurement costs, including for the non-performance of self-shown resources. Any backstop procurement costs allocated to the CPE should be allocated to all LSEs in the TAC area on a load ratio share basis.

    ~~b. If the CPM designation was due to the non-performance of self-shown local resources that failed to perform due to (1) a planned outage, or (2) any reason if the load-serving entity (LSE) is outside of the CPE's transmission access charge (TAC) area, then the CPE shall distribute the backstop costs evenly to all LSEs in the CPE's TAC area through the Cost Allocation Mechanism.~~

    ~~c. If the CPM designation was due to (1) the non-performance of a self-shown resources for any reason other than a planned outage, and (2) the resources were self-shown by an~~

~~LSE within the CPE's TAC area, the CPE shall be charged any associated CAISO backstop procurement costs. The CPE will then identify the non-performing self-shown resource, in coordination with Energy Division, and assign the resulting CAISO backstop costs to the LSE that attested to self-show the resource.~~

"Non-performance" is defined as the failure to provide: (a) the Commission with a Resource Adequacy plan with the self-shown local resource, and (b) the CAISO with a matching supply plan for the self-shown local resource. ~~Cost allocation shall not exceed the amount that was provided by the self-shown resource.~~

5. If a load-serving entity (LSE) either: (a) declines to self-show a local resource to the central procurement entity (CPE), or (b) declines to bid a local resource into the CPE's solicitation process, the LSE shall file a justification statement in its year-ahead Resource Adequacy filing explaining why the LSE declined to self-show or bid the local resource to the CPE. The justification statement is not meant as an enforcement mechanism but to improve the CPE framework and make adjustments as necessary.

12. The following timeline is adopted for central procurement entity (CPE) procurement for compliance year 2023. ~~and replaces the~~ The timeline adopted in Ordering Paragraph 28 of Decision 20-06-002 will continue beginning for compliance year 2024.~~:~~

- **April-May:** The California Independent System Operator (CAISO) files draft and final Local Capacity Requirement (LCR) one- and five-year ahead studies. The LCR studies will include any CAISO-approved transmission upgrades from the Transmission Planning Process LCR study. Parties file comments on draft and final LCR studies.

- **No Later Than Mid-May:** Load-serving entities (LSEs) in Southern California Edison (SCE) and Pacific Gas & Electric Company (PG&E) transmission access charge (TAC) areas make self-shown commitment of local resources to the CPE for the applicable Resource Adequacy (RA) years.

- **No Later than June:**

  - The Commission adopts multi-year local RA requirements for the applicable compliance years as part of its June decision.

  - For the SCE and PG&E TAC areas, LSEs receive Cost Allocation Mechanism (CAM) credits from CPE-procured system and flexible capacity from the prior year and any bilateral contracts.

- **No Later Than Early July:** CPE receives total jurisdictional share of multi-year local RA requirements for the applicable compliance years.

- **July:**

  - ~~For the SCE and PG&E TAC areas, LSEs receive initial RA allocations, including Cost Allocation Mechanism (CAM) credits from CPE-procured system and flexible capacity from the prior year and any bilateral contracts.~~

- For the San Diego Gas and Electric Company (SDG&E) TAC area, LSEs receive initial RA allocations (system, flexible, local requirements) and CAM credits.

- **Mid-August:** CPE makes local RA showing to the Commission.

- **End of August:** LSEs in the SCE and PG&E TAC areas receive updated CAM credits for multi-year system/flexible capacity that was procured by the CPE and the CPE's multi-year local RA showing to the Commission in Mid-August <u>resulting only from marginal changes between the 2021 and 2022 LCR.</u>

- **September:**
  - For PG&E and SCE's TAC areas, LSEs are allocated final year-ahead system and flexible RA allocations, including CAM credits from CPE-procured system and flexible RA capacity based on revised year-ahead load forecast load ratios.
  - For the SDG&E TAC area, LSEs receive final RA allocations (system, flexible, local requirements) and CAM credits.

- **End of October:**
  - LSEs in the SDG&E TAC make system, flexible, and three-year local RA showing
  - LSEs in PG&E and SCE TACs make year-ahead system and flexible showings, and provide justification statements, if applicable, for local resources not self-shown or bid to the CPE.
  - The CPEs and LSEs that committed to self-show make year-ahead showing to CAISO.

New Order: <u>Energy Division shall prepare a report assessing the effectiveness of the central procurement entity framework within Phase 3 of the Implementation Track in R.21-10-002.</u>

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Marin Clean Energy for Approval of 2024-2031 Energy Efficiency Business Plan and 2024-2027 Energy Efficiency Portfolio Plan	Application 22-03-___ (Filed March 4, 2022)

APPLICATION OF MARIN CLEAN ENERGY
FOR APPROVAL OF
2024-2031 ENERGY EFFICIENCY BUSINESS PLAN
AND
2024-2027 ENERGY EFFICIENCY PORTFOLIO PLAN

Jana Kopyciok-Lande
Strategic Policy Manager
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6044
E-Mail: jkopyciok-lande@mceCleanEnergy.org

Mad Stano
Policy Counsel
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6024
E-Mail: mstano@mceCleanEnergy.org

March 4, 2022

Table of Contents

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

Application of Marin Clean Energy for Approval of 2024-2031 Energy Efficiency Business Plan and 2024-2027 Energy Efficiency Portfolio Plan	Application 22-03-___ (Filed March 4, 2022)

**APPLICATION OF MARIN CLEAN ENERGY
FOR APPROVAL OF
2024-2031 ENERGY EFFICIENCY BUSINESS PLAN
AND
2024-2027 ENERGY EFFICIENCY PORTFOLIO PLAN**

I. INTRODUCTION

Marin Clean Energy (MCE) respectfully submits this Application for approval of its 2024-2031 energy efficiency (EE) Business Plan[1] and its 2024-2027 EE Portfolio Plan[2] pursuant to Article 2 of the California Public Utilities Commission's (Commission or CPUC) Rules of Practice and Procedure, California Public Utilities Code § 381.1 and Decision (D.) 21-05-031.[3]

MCE has successfully administered EE programs for nearly a decade.[4] MCE's EE programs have consistently delivered energy savings while also providing customer and community benefits.[5] While MCE's programs have primarily benefited communities local to MCE's service area, those programs have also supported the equitable growth of the EE market

---

1 MCE's 2024-2031 EE Business Plan is included as Exhibit 1 of the testimony served with this Application.

2 MCE's 2024-2027 EE Portfolio Plan is included as Exhibit 2 of the testimony served with this Application.

3 Rulemaking (R.) 13-11-005, D.21-05-031, *Assessment of Energy Efficiency Potential and Goals and Modification of Portfolio Approval and Oversight Process* (May 20, 2021).

4 Decision (D.)12-11-015, *Decision Approving 2013-2014 Energy Efficiency Programs and Budgets* at 50, OP 1 at 130 (November 15, 2012) (approving MCE EE portfolio).

5 *See* Marin Clean Energy, Customer Programs & Offerings, *available at*: https://www.mcecleanenergy.org/customer-programs/.

statewide. Through this Application, MCE seeks Commission approval to continue to deliver a balanced and diverse portfolio of EE programs to its residential, commercial, industrial, public and agricultural customers. MCE's four-year Portfolio Plan, covering the 2024-2027 period, largely builds on its existing portfolio of programs with innovative additions to serve customers in environmental and social justice (ESJ) communities. MCE's eight-year Business Plan, covering the 2024-2031 period, provides a longer-term strategic vision that is consistent with the near-term tactics and objectives in MCE's Portfolio Plan. MCE's Business Plan and Portfolio Plan, in concert, chart a path for MCE to scale the impact of its EE programming and support California's decarbonization goals. The Commission should approve both proposals, including MCE's annual budgets for program years (PY) 2024-2031.[6]

MCE also requests that the Commission authorize funding for MCE to continue to implement its Peak FLEXmarket program through PY 2027. Peak FLEXmarket uses a proven "pay-for-performance" (P4P) structure to deliver energy savings and demand reductions during summer peak periods.[7] In its recent Order on summer 2022 and 2023 electric reliability, the Commission authorized MCE to use $11 million in unrequested EE funds to scale Peak FLEXmarket in PYs 2022 and 2023,[8] recognizing that the program supports grid reliability and complements MCE's Efficiency Market programs. The Commission also acknowledged that Peak FLEXmarket is the model on which the new statewide "Market Access Programs" (MAPs) are based.[9] Moreover, in that same Order, the Commission encouraged EE program administrators

---

[6] MCE expects that its 2024-2031 budget, once approved, will set the budget cap for the eight-year period, while its 2024-2027 zero-based budget will establish its portfolio period spending budget.

[7] Summer peak periods are defined as 4 p.m. – 9 p.m. from June 1 through September 30.

[8] R.13-11-005, D.21-12-011, *Energy Efficiency Actions to Enhance Summer 2022 and 2023 Electric Reliability*, OP 2 at 60 (Dec. 2, 2021).

[9] *See* D.21-12-011 at 2.

(PA) to include proposals to extend their MAPs beyond PY 2023 in their 2022 EE applications.[10] It would therefore be appropriate for MCE to continue to use EE funds to implement Peak FLEXmarket in 2024-2027 and the Commission should authorize it to do so.

II. BACKGROUND

Since its founding as California's first community choice aggregator (CCA) in 2010, MCE has steadily increased the number of communities it serves, the customer programs it offers, and the impact it achieves. Today, MCE serves over 800,000 residential and non-residential customers in 37 diverse member communities across four San Francisco Bay Area counties (Marin, Napa, Solano and Contra Costa counties). MCE is the primary electric service provider in its service area and provides innovative customer programs that span the entire breadth of distributed energy resources (DERs).[11]

Energy efficiency is a pillar of MCE's mission and vision, and a critical resource to serve its customers' load.[12] MCE initially applied to administer EE programs in 2012, soon after its inception.[13] While the Commission initially restricted MCE to serving gaps in the investor-owned utilities' (IOU) EE programs,[14] the Commission subsequently lifted that restriction and allowed MCE to offer a more comprehensive portfolio of cost-effective EE programs.[15]

MCE filed its most recent application for Commission approval of its EE portfolio in 2017

---

10 D.21-12-011 at 27.

11 *See* Marin Clean Energy, Customer Programs & Offerings, *available at*: https://www.mcecleanenergy.org/customer-programs/.

12 *See* Marin Clean Energy, About Us, *available at*: https://www.mcecleanenergy.org/about-us/.

13 Application of Pacific Gas and Electric Company for Approval of 2013-2014 Energy Efficiency Programs and Budget, A.12-07-001 *et al.* (Jul. 2, 2012).

14 Application (A.) 12-07-001 *et al.*, D.12-11-015, *Decision Approving 2013-2014 Energy Efficiency Programs and Budgets* at 45-46 (Nov. 8, 2012).

15 *See* R.09-11-014, D.14-01-033, *Decision Enabling Community Choice Aggregators to Administer Energy Efficiency Programs*, OP 3 at 50 (Jan. 16, 2014).

(A.17-01-013 (consolidated)).[16] That portfolio included a comprehensive set of programs serving the residential single-family, residential multi-family, commercial, industrial and agricultural sectors, and met the Commission's cost-effectiveness requirements. The Commission approved MCE's proposed portfolio of programs and associated budgets in D.18-05-041,[17] The Commission also found that MCE's proposal was "thorough and thoughtful," noted that MCE's program ideas were "well-considered and innovative[,]" and that MCE had proposed "logical metrics and a small administrative structure to minimize costs."[18] Since that decision, MCE has steadily increased the breadth of its EE portfolio, launching five new programs for its residential and non-residential customers over the past four years.

III. LEGAL AND POLICY FRAMEWORK

MCE has administered EE programs under the authority granted in Cal. Pub. Util. Code § 381.1(a)-(d) since 2013. On May 20, 2021, the Commission issued an Order significantly modifying the EE portfolio approval and oversight process.[19] In addition to establishing several significant policy changes, D.21-05-031 directed all EE PAs to file new EE applications in 2022 containing the following elements:

1. An eight-year business plan describing the PA's strategic EE plan for PYs 2024-2031, and containing sector-level strategies, metrics, and an eight-year budget;
2. A four-year portfolio plan, providing a more detailed description of the EE portfolio and budget for PYs 2024-2027. The Commission requires that the portfolio plan specifically

---

16 *See* A. 17-01-013 *et al*., Application of Marin Clean Energy for Approval of its Energy Efficiency Business Plan (Jan. 17, 2017).

17 D.18-05-041, OP 33 at 189.

18 A.17-01-011 *et al.*, D.18-05-041, *Decision Addressing Energy Efficiency Business Plans* at 111 (May 31, 2018).

19 D.21-05-031 (May 20, 2021).

contain: detailed sector and program strategies; annual budgets, totaling to a four-year revenue requirement; cost-effectiveness showings over the four-year period; and program implementation plans. [20]

Accordingly, MCE files this Application, which requests Commission approval of MCE's eight-year EE Business Plan (included as Exhibit 1 in MCE's testimony) and MCE's four-year EE Portfolio Plan (included as Exhibit 2 in MCE's testimony). MCE's Business Plan and Portfolio Plan comply with each of the filing and substantive requirements in D.21-05-031 and prior Commission decisions. D.21-05-031 directed several significant changes to EE policy and the EE program approval and oversight process. The most notable changes include: (1) the adoption of Total System Benefits (TSB) as the single metric to be used to establish portfolio goals,[21] and (2) the segmentation of portfolios into Resource Acquisition, Market Support and Equity segments, with only Resource Acquisition segment programs required to meet a cost-effectiveness threshold.[22] Accordingly, MCE provides the TSB goals for its EE Portfolio Plan in Exhibit 2, Chapter 1 of its testimony, and has segmented its portfolio into Resource Acquisition, Market Support and Equity segments as described in more detail in Exhibit 2, Chapter 3 of its testimony. MCE's Resource Acquisition segment programs are cost effective, with a Total Resource Cost (TRC) ratio of 1.08 over the 2024-2027 period.

In addition to the Commission's directives, two pieces of legislation drive the development of MCE's 2024-2027 EE Portfolio Plan and associated annual budgets. The first is Senate Bill (SB) 350 (De León, 2015). SB 350 requires that the state double its EE savings by 2030 and

---

20 D.21-05-031, OP 5.

21 D.21-05-031, OP 1 at 80.

22 D.21-05-031, OP 2, 3 at 81.

enhance workforce development and training opportunities for residents in disadvantaged communities (DAC). Accordingly, MCE proposes to expand its EE programming and invest additional funding in its Workforce Education & Training (WE&T) program, as described in more detail in Exhibit 2, Chapter 4, Section 6 of MCE's testimony.

The second legislative driver is Assembly Bill (AB) 802 (Williams, 2015). AB 802 calls for EE incentive programs to use normalized metered energy consumption (NMEC) methods as the basis for measuring energy savings. NMEC-based programs already represent a core component of MCE's portfolio, and in this Application, MCE proposes to direct additional funding towards programs that use NMEC methods and that award incentives based on measured performance (including MCE's Residential and Commercial Efficiency Market and Peak FLEXmarket programs). These Marketplace programs are described in more detail in Exhibit 2, Chapter 3, Section 2 of MCE's testimony.

Finally, MCE also aligned the design of its Portfolio Plan and budgets with California's expanding building electrification and decarbonization policies.[23] MCE supports building electrification in its WE&T program, Strategic Energy Management (SEM) programming and by layering electrification programs available to customers through its "Any Open Door" strategy across proposed programs.[24]

IV. THE COMMISSION SHOULD APPROVE MCE'S APPLICATION

MCE requests Commission approval of its 2024-2027 EE Portfolio Plan, its 2024-2031 EE

---

23 *See e.g.* Exhibit 1, Chapter 1, Section 3.7 (including, but not limited to Senate Bill 1477, Skinner 2018; R.19-01-011; California Energy Commission's 2022 Building Energy Efficiency Standards).

24 MCE's "Any Open Door" strategy encourages customer engagement in EE programs by leveraging complementary energy programs for which the customer may be eligible. MCE describes its "Any Open Door" strategy in Exhibit 2, Chapter 3, Sections 2; 3; 4 (Resource Acquisition; Market Support; Equity Segments).

Business Plan, and standalone funding for its Peak FLEXmarket program for PY2 2024 -2027. MCE also requests that the Commission adopt several policy recommendations related to EE program and portfolio development.

A. The Commission Should Approve MCE's 2024-2027 Energy Efficiency Portfolio Plan, Including MCE's Proposed Annual Budgets.

MCE does not propose to make wholesale changes to its portfolio during the 2024-2027 Portfolio Plan period. Instead, MCE will fine-tune its existing portfolio—building on lessons learned from administering successful, locally-led EE programs since 2013—and incorporate innovations that meet new policy goals. The sections below explain how MCE's proposed 2024-2027 EE Portfolio Plan will benefit not only customers in MCE's service area but also all ratepayers.

1. MCE's Proposed Energy Efficiency Portfolio Plan and Annual Budgets are Reasonable.

MCE's 2024-2027 Portfolio Plan is reasonable because it includes a balanced set of program offerings that comprehensively address the needs of its agricultural, commercial, industrial, public and residential customers. Over the four-year Portfolio Plan period, MCE will implement cost-effective EE (and demand management) programs, while also supporting the sustained growth of the EE market in its service area and ensuring that all customers enjoy the benefits of EE, especially those historically underserved by EE programs.

MCE's customer base, which spans four Bay Area counties, is unique and diverse. While residential customers are the most prominent group among MCE's customer accounts, MCE also serves commercial, agricultural, public and industrial customers. A significant proportion of MCE's customers were born outside the United States, and nearly one-third of MCE's population base speaks a language other than English. Household incomes in MCE's service area vary widely—whereas household incomes are higher in Marin and Contra Costa counties, incomes are comparatively lower in Napa and Solano counties.

MCE's unique service area and customer base require MCE to employ a diverse set of strategies in order to achieve the portfolio outcomes it strives for. MCE's overarching portfolio strategies are to: 1) maximize TSB; 2) implement meaningful Equity programs; 3) support electrification and decarbonization efforts; 4) incorporate load shaping and demand response (DR); and 5) optimize delivery channels. MCE's portfolio—including its proposed annual budgets and goals—is reasonably designed to implement those strategies. The table below summarizes MCE's budget and goals[25] on an annual basis during the 2024-2027 portfolio period.[26]

Table 1: MCE Budget, TSB Goal and Energy Savings Targets for PYs 2024-2027

Program Year	Budget Request	Savings Target (kWh)	Savings Target (kW)	Savings Target (Therms)	Total System Benefit Goal
2024	$19,273,639	24,059,067	3,255	494,710	$15,540,846
2025	$19,522,249	24,059,067	3,255	494,710	$16,230,191
2026	$19,584,021	24,059,067	3,255	494,710	$17,098,384
2027	$19,837,407	24,059,067	3,255	494,710	$17,994,718
Total	**$78,217,316**	**96,236,268**	**13,020**	**1,978,840**	**$66,864,140**

MCE's annual Portfolio Plan budget is reasonable because it reflects a "zero-based" budgeting approach. The zero-based budgeting approach requires MCE to justify all expenses for each year of the four-year period after analyzing each function within the budget for its needs and costs.[27] To develop a zero-based budget, MCE considered the following factors in turn: (1)

[25] MCE's energy savings and TSB goals are not set through the bi-annual Potential and Goal (P&G) study completed by the Commission to determine the EE potential and goals for the IOU PAs. Instead, in D.21-09-037, the Commission determined that MCE may propose energy savings and TSB goals every four years through the portfolio application process and may propose to revise their goals and savings forecast in the true-up or mid-cycle advice letters. See D.21-09-037, OP5 at 30. Accordingly, MCE proposes energy savings and TSB goals for its 2024-2027 portfolio through this Application.

[26] The difference between the total and the sum of each year is due to rounding.

[27] D.21-05-031, OP 8 at 82.

regulatory and statutory requirements and legislative guidance; (2) MCE's mission and vision;[28] (3) an assessment of ongoing EE activities and emerging opportunities; and (4) an analysis of cost drivers, including staffing, implementation contracts and incentive costs.

D.21-05-031 contains the key regulatory requirements relevant to MCE's portfolio budget. Specifically, D.21-05-031 requires that PAs limit the expenditures on Market Support and Equity programs, combined, to a total of no more than 30 percent of their total portfolio budget.[29] MCE applied this requirement in developing the annual budget for its Market support and Equity segments over the portfolio period. Between PYs 2024 and 2027, Market Support and Equity programs make up 30% of MCE's EE portfolio.[30] MCE's portfolio budget is further informed by Senate Bill 350 (De León, 2015) and Assembly Bill 802 (Williams, 2015), which respectively require a doubling of EE by 2030 and the introduction of NMEC methods in EE programming.

MCE' mission and vision, which emphasize energy efficiency, also inform its budget. MCE's EE programs are central to achieving its mission by (1) reducing load and making it easier to meet renewable energy targets; (2) supporting the local economy and advancing Equity goals through Equity programming; and (3) supporting the local workforce through WE&T programs. As such, MCE's budget reflects an effort to invest as much as possible in EE while following the rules and regulations for ratepayer-funded EE programs established by the Commission.

MCE completed its zero-based budgeting exercise by assessing the activities associated with its existing EE portfolio, identifying emerging opportunities for EE deployment, and analyzing key cost drivers. To identify emerging opportunities, MCE analyzed several sources

---

[28] *See* Marin Clean Energy, About Us, *available at*: https://www.mcecleanenergy.org/about-us/.

[29] D.21-05-031, OP 4 at 81.

[30] *See* Exhibit 2, Chapter 3, Sections 3.1 and 4.1.

including the 2021 Potential and Goals (P&G) study[31] and the 2021 Avoided Cost Calculator (ACC). MCE's analysis of cost drivers included an examination of staffing and operational costs, implementation costs, marketing costs and incentives. MCE describes its assessment and analysis of cost drivers, and their impacts on PY 2024-2027 budgets, in Exhibit 2, Chapter 2 of its testimony.

2. MCE's Proposed Energy Efficiency Portfolio is Reasonably Designed to Meet the Goals of its Resource Acquisition, Equity and Market Support Segments.

Consistent with the Commission's directives in D.21-05-031,[32] MCE has divided its portfolio into Resource Acquisition, Market Support and Equity segments (described in more detail in Exhibit 2, Chapter 3 of MCE's testimony). MCE's Resource Acquisition segment includes programs that will deliver cost-effective avoided cost benefits to the electricity and natural gas systems. MCE designed these programs to maximize TSB while mitigating ratepayer risk and providing value to MCE's customers. MCE's Resource Acquisition programs are a combination of existing programs (for example, MCE's Commercial Efficiency Market, SEM and Behavioral Messaging programs) and new programs that build on strategies that MCE has successfully developed to date (for example, the expansion of NMEC-based Marketplace programs into the residential sector). MCE's Resource Acquisition segment has a forecasted TRC ratio of 1.08 over the Portfolio Plan period, which exceeds the Commission's ex-ante cost-effectiveness requirement (i.e., a TRC ratio of 1.0).[33]

MCE's Equity segment includes programs with a primary purpose of providing EE to

---

[31] *See* Cal. Pub. Util. Comm'n, 2021 Potential and Goals Study, *available at:* https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/energy-efficiency-potential-and-goals-studies/2021-potential-and-goals-study.

[32] D.21-05-031, OP2 at 81.

[33] D.21-05-031, OP3 at 81.

Equity customers[34] in advancement of the Commission's ESJ Action Plan.[35] The programs are designed to (1) provide energy efficiency and electrification opportunities; (2) deliver non-energy benefits (NEBs); and (3) reduce the energy burden for Equity customers. MCE's Equity programs offer (1) additional technical support; (2) reduced or no customer copays; (3) meaningful community engagement; and (4) targeted marketing to participating customers. They are geared at customers that would otherwise be challenging to serve under the cost-effectiveness requirements applicable to the Resource Acquisition segment. Improving access to EE for Equity customers achieves energy savings and can also provide extremely valuable NEBs, such as (1) increased health, comfort and safety; (2) improved indoor air quality; and (3) more affordable utility bills. These NEBs are consistent with Goals 1, 2, and 5 in the Commission's ESJ Action Plan.[36]

MCE's Market Support segment consists of a single program, the WE&T program, which is tailored to support a workforce that can install advanced EE and electrification measures. This program does not claim savings but instead supports other programs that incentivize building electrification by increasing the available contractor pool. As a part of this program, MCE will provide training for EE contractors and job-seekers in the sustainable energy field; match job-seekers with energy contractors for paid, on-the-job training; and follow best practices from

---

34 MCE refers to all categories of customers eligible for its proposed Equity segment programs using the umbrella term "Equity customers." Consistent with D.21-05-031, MCE defines "Equity customers" as residential customers and businesses within identified "Environmental and Social Justice Communities" (ESJ Communities) by the Commission's Environmental and Social Justice Action Plan, with the additional modifier of households at or below 400% of the Federal Poverty Level (FPL) or 80% of Area Median Income. *See* Exhibit 2, Chapter 3, Section 4.2 of MCE's testimony.

35 *See* Cal. Pub. Util. Comm'n, Environmental and Social Justice Action Plan version 1.0 (Feb. 21, 2019), available at: https://www.cpuc.ca.gov/news-and-updates/newsroom/environmental-and-social-justice-action-plan ("ESJ Action Plan").

36 *See* ESJ Action Plan at 6-8.

industry leaders in creating high-quality employment.

The table below summarizes MCE's requested budget on an annual basis, disaggregated by segment, during the 2024-2027 Portfolio Plan period.[37]

Table 2: MCE Budget Disaggregated by Segment for PYs 2024-2027

Program Year	Segment	Budget Request
2024	Resource Acquisition	$12,720,602
	Market Support	$1,033,676
	Equity	$4,748,416
	Total	**$18,502,694**
2025	Resource Acquisition	$12,884,684
	Market Support	$1,014,783
	Equity	$4,841,891
	Total	**$18,741,359**
2026	Resource Acquisition	$12,925,454
	Market Support	$1,017,752
	Equity	$4,857,455
	Total	**$18,800,660**
2027	Resource Acquisition	$13,092,689
	Market Support	$1,002,206
	Equity	$4,949,016
	Total	**$19,043,911**

3. MCE's Portfolio Includes Robust and Targeted Programs in the Agricultural, Commercial, Cross-Cutting, Industrial and Residential Sectors.

Over the Portfolio Plan period, MCE will continue to offer programs in the agricultural, commercial, industrial and residential sectors, as well as a cross-cutting WE&T program. MCE emphasizes its residential and commercial sector programming because the residential sector makes up the highest number of MCE customer accounts (approximately 90%) while the commercial sector provides the greatest opportunities for achieving cost-effective savings.

With respect to the residential sector, MCE proposes two primary goals: (1) serve low- to moderate-income customers with comprehensive offerings that save energy and money while

[37] The difference between the total and the sum of each segment is due to rounding.

providing additional NEBs; and (2) serve market-rate residential customers with programs that meet or exceed TSB requirements. To meet its residential customers' needs, MCE will (1) encourage low- to no-cost savings through behavioral messaging; (2) diversify its network of EE providers by implementing a residential Efficiency Market program (mirroring its existing, successful Commercial Efficiency Market program); (3) complement and fill gaps in existing EE programs; and (4) network within communities to identify eligible Equity customers.

With respect to the commercial sector, MCE proposes the following strategies to meet its portfolio goals. MCE will (1) scale incentives based on TSB; (2) employ varied delivery channels (including both the Marketplace model as well as a "direct support" model); (3) facilitate financing solutions for both customers and aggregators;[38] and (4) develop a new Commercial Equity program to provide support and services to commercial Equity customers.[39]

MCE will also deploy certain strategies that are common to both its residential and commercial sectors. For instance, in both the residential and commercial sectors, MCE will (1) implement SEM programs; (2) use data analytics to target customers with high savings or TSB potential; and (3) emphasize coordination with other programs through an "Any Open Door" strategy which leverages EE as an opportunity to promote complementary sustainability and energy offerings.

MCE's industrial sector strategies substantially mirror its agricultural sector strategies. In order to address common pain points and achieve cost efficiencies, MCE will implement a joint

---

[38] In this Application, MCE defines an "aggregator" as a vendor or provider of an energy efficiency or demand management service that aggregates a number of customers under a combined offering for participation in a MCE Marketplace program. An aggregator is distinct from a traditional program "implementer" which MCE defines in this Application as a single implementation partner under a particular EE program (not a Marketplace program).

[39] MCE defines "Commercial Equity customers" for the purposes of this Application as businesses in ESJ communities. *See* Exhibit 2, Chapter 3, Section 4.2.

program that targets both agricultural and industrial customers (the MCE Agricultural and Industrial Resource or "AIR" program). In addition, similar to strategies that MCE will deploy in its residential and commercial sector programming, MCE will serve its agricultural and industrial customers by (1) scaling incentive payments based on TSB of a project; (2) implementing SEM programming; (3) emphasizing coordination with other programs through the "Any Open Door" strategy; and (4) using data analytics to target customers with high savings potential.

Finally, MCE's cross-cutting WE&T program will increase the capacity of the workforce to install and maintain emerging EE and electrification measures and create opportunities for sustainable employment in the building electrification industry. The WE&T program is MCE's only program in the Market Support segment, and MCE's strategies for achieving its Market Support segment's goals are further described above.

Through these sector-specific strategies, which are described in more detail in Exhibit 2, Chapter 4 of MCE's testimony, MCE's portfolio will comprehensively address the needs of its agricultural, industrial, commercial and residential customers. MCE will also continue to serve public sector customers through its existing EE programs depending on their specific characteristics and energy usage patterns. For example, MCE will continue to engage with public water and wastewater agencies under its industrial program.

The table below summarizes MCE's requested budget on an annual basis, disaggregated by sector, during the 2024-2027 portfolio period.[40]

---

40 The difference between the total and the sum of each sector is due to rounding.

Table 3: MCE Budget Disaggregated by Sector (2024-2027)

Program Year	**Sector**	**Budget**
2024	Agricultural	$726,866
	Commercial	$7,948,028
	Industrial	$1,087,157
	Residential	$7,706,967
	Cross-Cutting	$1,804,621
	Total	**$19,273,639**
2025	Agricultural	$732,727
	Commercial	$8,056,302
	Industrial	$1,092,434
	Residential	$7,845,113
	Cross-Cutting	$1,795,673
	Total	**$19,522,249**
2026	Agricultural	$738,999
	Commercial	$8,066,539
	Industrial	$1,098,080
	Residential	$7,879,290
	Cross-Cutting	$1,801,113
	Total	**$19,584,021**
2027	Agricultural	$745,710
	Commercial	$8,186,167
	Industrial	$1,104,122
	Residential	$8,005,707
	Cross-Cutting	$1,795,702
	Total	**$19,837,407**

4. MCE's Marketplace Programs are a Pillar of its Programming Strategy.

MCE is a pioneer in pairing NMEC-based energy savings and demand reduction quantification with a pay-for-performance (P4P) program structure. MCE has developed the capacity to deploy P4P Marketplace programs that use NMEC measurement methods since 2016 and expects those innovative programs to be a pillar of its programming strategy in the 2024-2027 portfolio cycle and beyond. In this Application, MCE proposes three Marketplace programs—the

EE-focused Commercial Efficiency Market and Residential Efficiency Market, as well as the demand management-focused Peak FLEXmarket program.[41]

MCE's Efficiency Market programs rely on meter data to assess customer load and quantify hourly savings profiles, which are used to make payments based on the actual performance of an EE measure (*i.e.*, the avoided cost value of quantified savings). Payments in the Efficiency Market programs vary not only based on total energy savings, but also on *when* those savings occur—which creates a direct linkage between incentives and value delivered to the system. Similarly, MCE's Peak FLEXmarket program assigns an hourly value to demand reduction and makes payments to providers based on measured impacts during peak periods. MCE will also leverage the Marketplace program model to incorporate low-global warming potential (low-GWP) refrigerants into its portfolio by paying aggregators incentives that align with the TSB of refrigerant conversion projects.

MCE's Marketplace programs are innovative for a variety of reasons. First, the programs not only align incentives and program expenditures with delivered system benefits, but also inherently evolve in parallel with updates to avoided cost calculations (since "performance" under the program is linked to the Commission's ACC[42]).

Second, MCE's Marketplace programs produce an important ancillary benefit: instead of relying on a small, select group of implementation partners (as is common in traditional EE portfolios), Marketplace programs open the door to a much larger group of providers. This not only results in MCE's customers having access to a more diverse set of services under a single

[41] *See* MCE's request for standalone EE funding for its Peak FLEXmarket program at Section IV.C. of this Application; *see also* Exhibit 2 Chapter 8 of MCE's testimony describing the Peak FLEXmarket program.

[42] In the case of refrigerant projects, performance would be linked to the Refrigerant Avoided Cost Calculator.

program umbrella, but also reduces performance risk to all ratepayers. That is because, unlike the traditional solicitation and contract management model, the Marketplace model does not tie funding to individually contracted implementation partners subject to payment caps tied to assumed deliverable value. Instead, Marketplace programs allocate funding to providers who have submitted complete projects, and those funds are only paid once the TSB of metered projects has been verified. This minimizes the risks of portfolio underperformance, programmatic downtime and administrative waste. Indeed, the Commission has recognized that the basic structure of MCE's Marketplace programs presents very low risk to ratepayers because it (1) requires measurement of actual energy savings using NMEC methods; (2) links payments to performance; and (3) limits program spending by total system benefit achieved.[43]

Third, MCE's Marketplace programs promote flexibility and efficiency by offering aggregators significant leeway to develop customer offerings as they see fit, based on each provider's strengths, business models, and variable customer needs, rather than based on prescriptive measure lists. While aggregators drive customer engagement under the Marketplace model, MCE supports participating aggregators by offering co-branded marketing collateral, data analytics, financing opportunities, and support from MCE's business relationship managers.

To maximize the several benefits of the Marketplace model, MCE proposes to increase its emphasis on Marketplace programs over the portfolio plan period. MCE's 2024-2027 budgets include increased funding for its Commercial Efficiency Market program, as well as a funding request for a new Residential Efficiency Market program. Relatedly, MCE's standalone request for its Peak FLEXmarket program in the 2024-2027 portfolio plan period will allow it to continue expanding the innovative Marketplace model into the demand management area, thereby

[43] D.21-12-011 at 30-31.

achieving increased peak demand reductions and supporting grid reliability.

B. The Commission Should Approve MCE's Proposed 2024-2031 Energy Efficiency Business Plan, Including its Proposed Budget Cap.

MCE's 2024-2031 Business Plan provides the long-term strategic overlay to MCE's near-term Portfolio Plan strategies, expected outcomes and budgets as described above. As such, the eight-year Business Plan is an extension of the four-year Portfolio Plan. Importantly, MCE has intentionally designed its Business Plan such that it is philosophically consistent with the Portfolio Plan. Over the eight-year Business Plan period, MCE will continue to 1) aim to maximize TSB through the implementation of cost-effective EE programs; 2) support the sustained growth of the EE market in its service area; 3) foster the closer integration of EE and demand management strategies and 4) ensure that all customers enjoy the benefits of EE, especially those historically underserved by EE programming. The table below summarizes MCE's requested budget, TSB goals and energy savings targets on an annual basis during the 2024-2031 Business Plan period.

Table 4: MCE Budget, TSB Goals and Energy Savings Targets (PYs 2024-2031)

Program Year	Budget Request	Savings Target (kWh)	Savings Target (kW)	Savings Target (Therms)	Total System Benefit Goal[44]
2024	$19,273,639	24,059,067	3,255	494,710	$15,528,383
2025	$19,522,249	24,059,067	3,255	494,710	$16,218,045
2026	$19,584,021	24,059,067	3,255	494,710	$17,085,620
2027	$19,837,407	24,059,067	3,255	494,710	$17,981,263
2028	$19,905,308	24,059,067	3,255	494,710	$18,891,597
2029	$19,976,604	24,059,067	3,255	494,710	$19,826,995
2030	$20,051,465	24,059,067	3,255	494,710	$20,774,384
2031	$20,130,069	24,059,067	3,255	494,710	$21,849,369
Totals	**$158,280,762**	**192,472,536**	**26,040**	**3,957,680**	**$148,206,484**

44 MCE's energy savings and TSB goals are not set through the bi-annual Potential and Goal (P&G) study completed by the Commission to determine the EE potential and goals for the investor-owned utility program administrators. Instead, in D.21-09-037, the Commission determined that MCE may propose energy savings and TSB goals every four years through the portfolio application process and may propose to revise their goals and savings forecast in the true-up or mid-cycle advice letters. D.21-09-03, OP5 at 30.

MCE's Business Plan and associated budgets are reasonable because they are an extension of the strategies in its four-year Portfolio Plan and because they anticipate continued evolution in California's energy goals. As California's energy goals evolve, new market and technology opportunities emerge, and the Commission institutes new demand-side management policies and directives, MCE will continue to innovate and diversify its program offerings. MCE expects that over the Business Plan period (1) its meter-based and pay-for-performance programs will continue to grow; (2) electrification programs will become a more prominent feature of its portfolio; (3) decarbonization will play an increasingly important role in portfolio planning, and; (4) EE programs will be more closely integrated with other demand-side management offerings. Consistent with D.21-05-31, MCE will file a Portfolio Plan application for PYs 2028-2031 in which it will detail its program strategies for that future period in more detail.

C. The Commission Should Approve MCE's Standalone Request for Funding of its Peak FLEXMarket Program for Program Years 2024-2027.

In light of California's increasing focus on long-term grid reliability needs,[45] the Commission has called for greater integration between EE and demand management programs to help deliver improved reliability outcomes.[46] The Commission's interest in integrating EE and demand management programs correctly recognizes the complementary relationship between EE and demand management measures (*i.e.*, EE measures deliver demand reductions, and demand reduction measures deliver energy savings during certain times). In 2017, Commission staff proposed the integration of certain aspects of EE andDR activities, including residential heating, ventilation and air conditioning (HVAC) controls, non-residential HVAC and lighting controls, as

---

[45] *See e.g.* Executive Department State of California, Proclamation of a State of Emergency, July 30, 2021, https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf.

[46] R. 13-11-005, *Ruling requesting comments/ proposals to address Governor's Proclamation of July 30, 2021* (August 6, 2021).

well as DR and EE potential studies to support analysis under the integrated resource planning (IRP) process.[47] In its Order on the PAs' 2017 portfolio applications, the Commission adopted a set of general requirements for utility PAs to begin to integrate delivery of EE and DR capabilities to customers.[48] The Commission also encouraged non-utility PAs, such as MCE, to solicit third-parties to design and implement programs to test various strategies and technologies for integrating DR capabilities with existing EE activities.[49]

The Commission should continue to foster the closer integration of EE and demand management programs in this proceeding to maximize high value energy savings. Specifically, MCE requests that the Commission authorize MCE to continue to use EE funds to scale its Peak FLEXmarket demand management program during the 2024-2027 portfolio period. Peak FLEXmarket is a proven and innovative demand management program that complements MCE's Residential and Commercial Efficiency Market programs. MCE's Efficiency Market programs compensate aggregators based on the avoided cost value of their projects, which means that savings occurring during peak hours receive higher payments than savings occurring during off-peak hours. Peak FLEXmarket shares the same fundamental meter-based payment structure as the Efficiency Market programs, but incentivizes load shifting, load shaping and demand reduction during peak summer hours. MCE's Efficiency Market programs and Peak FLEXmarket, operating in tandem, will spur the development of new projects that combine efficiency and demand management measures, thereby unlocking the value of demand management from the same providers that deliver traditional energy savings. The demand reductions and energy savings that

---

47 D.18-05-041 at 30.

48 D.18-05-041, COL 9 at 171; OP 10 at 184.

49 D.18-05-041 at 36.

MCE's Marketplace programs deliver will support the state's goal to increase energy savings while also supporting grid reliability, which is an issue of increasing concern in California.

The table below summarizes MCE's requested annual budget and forecasted goals for the Peak FLEXmarket in PYs 2024-2027.

Table 5: Peak FLEXmarket Budget and Goals for PYs 2024-2027

Program Year	Budget	Peak[50] Demand Reduction (MW)	Peak energy savings (MWh)
2024	$6,570,000	22.5	4,950
2025	$6,570,000	22.5	4,950
2026	$6,570,000	22.5	4,950
2027	$6,570,000	22.5	4,950
Total	**$26,280,000**	**90**	**19,800**

The Commission has previously authorized MCE to use EE funds to scale Peak FLEXmarket. In D.21-12-011, the Commission authorized MCE to redeploy $11 million in unrequested EE funds to augment its Peak FLEXmarket program budget in 2022 and 2023.[51] Moreover, in that decision, the Commission authorized PAs to propose extensions to their MAPs in their 2022 EE applications, and acknowledged that MAPs are modeled on MCE's Efficiency Market and Peak FLEXmarket programs.[52] Peak FLEXmarket will remain an important complement to MCE's Efficiency Market programs beyond 2023 and therefore the Commission should authorize MCE to continue to use EE funds to implement Peak FLEXmarket in PYs 2024-2027.

MCE is including the request for approval of Peak FLEXmarket as distinct from its EE portfolio, including its 2024-2027 budgets and goals. This is because the Commission's Cost

50 Peak periods are defined as 4pm - 9pm between June 1 and September 30 each year.

51 D.21-12-011, OP 2 at 60.

52 D.21-12-011, at 24; 30.

Effectiveness Tool (CET)—which MCE and other EE PAs use to calculate the TSB and cost-effectiveness of their programs—cannot currently calculate the impacts of a demand management program accurately. The CET currently requires PAs to choose a prescriptive load shape and provide an effective useful life (EUL) of at least one year for each participating measure. However, demand management measures (such as those incentivized by the Peak FLEXmarket) are often developed to deliver energy savings and peak demand reductions only during the peak hours of summer months. The CET therefore cannot accurately forecast the TSB associated with demand management measures. If MCE had incorporated Peak FLEXmarket into its Resource Acquisition segment, it would not have been able to calculate the cost-effectiveness of that segment as required by D.21-05-031. MCE therefore requests that the Commission approve MCE's standalone budget request for Peak FLEXmarket.

D. Recommendations for New or Modified Energy Efficiency Policies

MCE includes its recommendations for new or modified EE policies in Exhibit 1, Chapter 3 of its testimony, and summarizes those recommendations briefly below.

1. The Commission Should Bolster the Cost Effectiveness Tool and the California Energy Data and Reporting System.

The Commission's CET is housed within the California Energy Data and Reporting System (CEDARS) and is used to calculate TSB and cost-effectiveness associated with EE programs. The CET is a critical tool on which all EE PAs rely to develop their portfolios—including budgets and energy savings targets. The CET and CEDARS require both additional resources and functionality to allow ongoing maintenance and to improve the efficiency of program and portfolio development. To this end, MCE offers the following policy recommendations:

- Direct additional funding to CEDARS;
- Establish a "governance committee" for both the CET and CEDARS;

- Add an application programming interface (API) to the CET and CEDARS to allow system-to-system communication between PAs' and implementers' data systems and the CET and CEDARS;
- Direct the creation of a more transparent, accessible and robust set of documentation and trainings for CET users, and;
- Allow CPUC-contracted evaluators to view and access more detailed program tracking data through CEDARS.

Collectively, these improvements would make the CET and CEDARS more robust which in turn would significantly increase the efficiency of EE portfolio and program development and evaluation.

2. The Cost Effectiveness Tool Should be Modified to Appropriately Value the Impacts of Demand Reduction Measures.

The CET, as it is currently designed, is focused on calculating the cost-effectiveness and TSB of EE measures and is not designed to calculate the impacts of demand reduction measures. Specifically, the CET does not calculate avoided costs and thus TSB for DR events (*i.e.*, designated instances during which customers are asked, in advance, to reduce their energy demand temporarily). As described in section C above, the CET requires PAs to choose a prescriptive load shape and provide an EUL of at least one year. However, many demand management measures are heavily—and sometimes entirely—geared towards achieving energy savings and peak demand reductions during peak hours of summer months.

In its recent Decision (D.) 21-12-011 regarding summer 2022 and 2023 electric reliability, the Commission approved the MAP, which incentivizes implementers to find EE projects that deliver measurable peak or net peak demand savings.[53] As a part of that program, incentives will be adjusted to include a "kicker" payment for peak and net peak savings delivered between June 1 and September 30 of PYs 2022 and 2023. Unfortunately, the CET, as it is currently designed, cannot appropriately calculate peak and net peak savings, which will make it difficult to calculate TSB and cost effectiveness ratios for programs that include kicker payments.

Like the MAP, MCE's Peak FLEXmarket program offers incentives for load shifting during summer peak hours. It also incentivizes demand reduction during periods of high grid congestion, power shortages, or high prices (*i.e.* DR events). The CET's limitations described above make it difficult for MCE to calculate the demand impacts of the Peak FLEXmarket program appropriately.

To implement the Commission's direction on new MAPs and to enable MCE's Peak FLEXmarket program and similar innovative programs that integrate EE with demand reduction strategies, the Commission should modify the CET to allow for the use of custom load shapes and the calculation of TSB for partial hours of the year. This will enable PAs to appropriately value the impact of demand reduction measures, and incorporate these measures into the Resource Acquisition segment of their respective portfolios on equal footing with EE measures. Additionally, MCE recommends the Commission conduct workshops to better align cost-effectiveness metrics with DR metrics and updated policy goals starting in 2024.

3. The Commission Should Establish Clear Deadlines for Updating Technical Tools and Templates.

As described above, the CET is a tool that serves as the very basis on which PAs build their portfolios. Without easy and consistent access to that tool during portfolio planning, PAs cannot

[53] D.21-12-011, OP1 at 59. As the Commission noted, the Market Access program is modeled on MCE's Peak FLEXmarket program, described in more detail in Exhibit 2, Chapter 8. D.21-12-011, p. 24.

develop their portfolio plan or budget, develop TSB and energy savings targets, and determine which programs are cost-effective. Currently however, PAs' portfolio planning efforts are frequently hamstrung by unavailability or late updating of the CET before a filing deadline. The Commission should implement process changes such that PAs have sufficient time to adapt to changes in cost effectiveness results before a CET showing is required. This would help avoid situations where PAs are forced to rework portfolios on timelines that are significantly shorter than the original timelines provided to develop cost effectiveness showings.

To this end, MCE recommends that the Commission direct Energy Division staff finalize all technical tools necessary for portfolio planning at last 90 days before the submission of any future Advice Letter (AL) filing (*e.g.*, the true-up or mid-cycle AL) or at least 120 days before any future portfolio plan filing (*i.e.*, the Application for PYs 2028-2031). Further, if the technical tools are not ready on that timeline, the Commission should automatically extend the filing deadline to ensure that all technical tools are finalized at least 90 days before an AL submission and 120 days before a portfolio plan filing. This will allow PAs enough time, generally, to revise their filings more efficiently and without needing to deprioritize core implementation work.

4. The Commission Should Direct MCE and PG&E to Exchange Demand Response Program Participation Data on a Quarterly Basis

While EE program coordination and data sharing processes between Pacific Gas & Electric (PG&E) and MCE have improved in recent years, a greater exchange of information for DR programs is needed. The state is acutely and appropriately focused on reliability, and recently approved new IOU DR programs.[54] These and other DR programs have limitations on dual participation in demand management programs. Hence, PG&E and MCE must exchange program

[54] *See e.g.* D.21-12-015, OP 7 (authorizing the Residential Emergency Load Reduction Program).

participation information to help verify customer eligibility and avoid customers' dual participation in a demand management program. To date, PG&E has generally asserted that customer confidentiality impedes data sharing on DR programs, but those concerns are misplaced given the CCAs' long-standing non-disclosure agreements with PG&E, which would ensure that the confidentiality of customer data is protected. Absent Commission direction on coordination, it will be infeasible for MCE or PG&E to verify customer eligibility given the need to generally avoid enrolling customers in multiple demand management programs. MCE therefore recommends that the Commission direct PG&E and MCE to share program participation data for all DR programs, tariffs and pilots on a quarterly basis.

5. The Commission Should Continue To Evaluate the Future Use of the Program Administrator Cost Test Instead of the Total Resource Cost Test to Evaluate the Cost-Effectiveness of the Resource Acquisition Segment

Per D.21-05-031, PAs are required to demonstrate that the Resource Acquisition segment of their respective portfolios are cost effective on an ex-ante basis (i.e., meet or exceed a Total Resource Cost (TRC) ratio of 1.0 on an ex-ante basis). MCE conceptually agrees that for the Resource Acquisition segment of EE portfolios, benefits should be equal to, or greater than, costs. However, the TRC is not the appropriate ratio to use to accurately and meaningfully compare the costs and benefits of current EE programs. That is because the TRC test is fundamentally asymmetric: it includes participant *costs* but fails to include important participant *benefits* such as NEBs. This results in an "apples to oranges" comparison that skews cost-effectiveness results. Additionally, NEBs exclusion also discourages participation of Equity customers in EE programs.[55]

[55] See MCE Application, V, C, 5; Policy Recommendation 5; Exhibit 1, Chapter 3, Section 1.6.

In contrast, the Program Administrator Cost (PAC) test considers only those costs and benefits the PA incurs, and not those the customer incurs. The PAC test therefore provides a much better "apples to apples" comparison of the benefits and costs of EE programs. The Commission has previously recognized the potential merits of the PAC test and the need to update cost-effectiveness measurements, but has on more than one occasion declined to order a move away from the TRC test. In D.21-05-031, the Commission stated that while it recognized the merits of the PAC test, it would test out its new approach to portfolio segmentation (in which only programs in the Resource Acquisition segment are subject to cost effectiveness requirements) before making any changes to threshold cost-effectiveness assessment requirements.[56] MCE acknowledges that, for the purposes of the 2024-2027 portfolio cycle, the Commission would like to test its new segmentation approach before making any changes to cost effectiveness threshold requirements. However, in the longer run, MCE continues to encourage the Commission to consider a future transition from the TRC to the PAC test. For this reason, MCE suggests that the Commission establish cost-effectiveness workshops starting in 2024 to explore this issue in time to implement a shift to the PAC in the following four-year portfolio cycle.

6. The Commission Should Develop Non-Energy Benefits as an Indicator for the Equity Segment of Energy Efficiency Portfolios.

MCE strongly supports the vital development of NEB metrics in EE programs and within the Equity segment of this Application. NEBs like health, safety, comfort and reduced energy burdens are often the primary motivation and justification for EE investments in general, and in Equity communities in particular. Consistent with the Commission's ESJ goal to promote

[56] D.21-05-031 at 67-68.

investment in clean energy resources that benefit Equity customers[57]and the California Energy Efficiency Coordinating Committee (CAEECC) Equity Group's consensus recommendation,[58] MCE supports expanding existing EE metrics to better promote equitable outcomes through NEBs.

MCE's recommendation is aligned with the Commission's recognition in D. 21-05-031 that it "may consider whether or how to transition to an evaluation of non-energy benefits when considering the reasonableness of costs related to market support and equity programs."[59] Further, in D.21-05-031, the Commission acknowledged: "All parties seem to agree that the current focus on first-year energy savings only, in the form of kWh, kW, and therm savings, does not capture all of the policy goals and benefits of energy efficiency. We agree."[60]

The failure to consider and value NEBs represents a key barrier to EE investments benefiting Equity customers. Equity customers experience many structural, market and policy barriers to EE programs. For example, EE projects in older buildings within ESJ communities often require additional retrofits and treatments than newer buildings, resulting in higher comparative costs. Current evaluation methodologies, that do not consider NEBs, functionally discourage projects in the households, business and communities that need them the most, because they ignore many of the key benefits that the projects will deliver to participants. These same households, businesses and communities are simultaneously disproportionately experiencing higher energy burdens, greater pollution from California's energy system, higher disconnection

---

57 Cal. Pub. Util. Comm'n, Environmental and Social Justice Action Plan, version 1.0 at 15 (Feb. 21, 2019).

58 CAEECC Equity Metrics Working Group, October 2021, Report and Recommendations to the California Public Utilities Commission and the Energy Efficiency Program Administrators Equity Working Group Final Report, at 19-20, available at: https://www.caeecc.org/equity-metrics-working-group-meeting.

59 D.21-05-031 at 23-24.

60 D.21-05-031 at 8.

risks and wildfire impacts. Failing to consider NEBs risks widens the already existing "climate gap" of environmental and social inequalities for Equity customers across California. That would run directly counter to the Equity segment's primary purpose of "providing energy efficiency to hard-to-reach or underserved customers and disadvantaged communities."[61] MCE therefore urges the Commission to use NEBs as an indicator for the Equity segment.

V. ORGANIZATION OF MCE'S TESTIMONY

In support of this Application, MCE provides testimony describing its 2024-2031 EE Business Plan and 2024-2027 EE Portfolio Plan. Exhibit 1 of MCE's testimony describes the eight-year Business Plan. It details MCE's strategic vision, provides annual budgets, and recommends new and modified EE policies for the Commission's consideration. Exhibit 2 of MCE's testimony describes the four-year portfolio plan in detail. It provides extensive information regarding MCE's portfolio and budget, including in particular:

- A summary of MCE's Portfolio Plan (Chapter 1);
- Forecasting methodology and budget, based on a zero-based budgeting approach (Chapter 2);
- Segmentation strategy (Chapter 3);
- Sector-specific strategies (Chapter 4);
- Portfolio management approaches (Chapter 5);
- Evaluation, measurement and verification (EM&V) considerations (Chapter 6);
- Portfolio cost summaries (Chapter 7); and
- A description of MCE's Peak FLEXmarket (Chapter 8).

Exhibit 3 of MCE's testimony includes the following set of appendices to MCE's testimony:

61 D.21-05-031 at 14-15.

- Appendix A: Budget Filing Appendix;
- Appendix B: Supplemental Budget Narrative;
- Appendix C: Proposed Equity and Market Support Segment Metrics;
- Appendix D: Budget Details by Program; and
- Appendix E: CEDARS Filing Receipt.

Consistent with the Commission's requirements, Exhibit 1 and 2 of MCE's testimony adhere to a template approved by the Commission's Energy Division. Exhibit 3 of MCE's testimony follows the guidance provided by Energy Division staff and/or CAEECC.

VI. COMPLIANCE WITH THE COMMISSION'S RULES OF PRACTICE AND PROCEDURE

In the sections below, MCE provides certain information regarding its Application, its supporting testimony and its corporate form in compliance with the Commission's Rules concerning applications.

A. Summary of Relief Sought - Rule 2.1

MCE respectfully requests that the Commission expeditiously approve this Application and grant the following relief:

- Approve MCE's 2024-2027 EE Portfolio Plan described in Exhibit 2 of MCE's testimony, and associated annual budgets described in Exhibit 2, Chapter 1 of MCE's testimony;
- Approve MCE's 2024-2031 EE Business Plan described in Exhibit 1 of MCE's testimony, and associated budget cap described in Exhibit 1, Chapter 2 of MCE's testimony;
- Approve funding for MCE's Peak FLEXmarket program for PYs 2024-2027, consistent with the budget described in Exhibit 1, Chapter 2 of MCE's testimony in support of this Application;
- Bolster the Cost Effectiveness Tool and the California Energy Data and Reporting System;
- Modify the Cost Effectiveness Tool to appropriately value the impacts of demand

reduction measures;

- Establish clear deadlines for updating technical tools and templates;
- Direct MCE and PG&E to exchange DR program participation data on a quarterly basis;
- Continue to evaluate the future use of the PAC test instead of the TRC test to evaluate the cost-effectiveness of the Resource Acquisition segment, and;
- Develop non-energy benefits as an indicator for the equity segment of EE portfolios.

B. Statutory Authority - Rule 2.1

MCE is applying to continue administering EE programs under the authority granted in Cal. Pub. Util. Code § 381.1(a)-(d) and its obligations to procure EE on behalf of its customers as directed by Cal. Pub. Util. Code § 366.2(a)(5) and § 454.5(b)(9)(C).

C. Legal Name & Principal Place of Business - Rule 2.1(a)

The legal name of the Applicant is Marin Clean Energy. MCE's principal place of business is San Rafael, California. Its address is 1125 Tamalpais Avenue, San Rafael, CA 94901. MCE is a joint powers authority formed under the laws of California.

D. Correspondence and Communication Regarding this Application - Rule 2.1(b)

MCE consents to email service of all notices, orders and other correspondence and communications relating to this Application. All correspondence and communications regarding this Application should be addressed to:

Mad Stano
Policy Counsel
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6024
E-Mail:mstano@mceCleanEnergy.org

Jana Kopyciok-Lande
Strategic Policy Manager
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6044
E-Mail: jkopyciok-lande@mceCleanEnergy.org

E. Categorization - Rule 2.1(c)

The Commission should categorize this Application as a "ratesetting" proceeding under Commission Rule 7.1(e)(2) because it does not clearly fit into any of the categories as defined by Rules 1.3(a), 1.3(b), 1.3(f) and 1.3(g). MCE's Application does not meet the definition of adjudicatory in Rule 1.3(a) because it is neither an enforcement investigation nor a complaint. MCE's Application is not a "catastrophic wildfire proceeding" as defined in Rule 1.3(b) because it does not involve an application to recover costs and expenses related to a wildfire. MCE's Application does not fit the definition of a "quasi-legislative proceeding" under Rule 1.3(f) because the application does not require the Commission to establish policy or rules affecting a class of regulated entities, and because the Application requests the Commission to grant relief that is specific to MCE. And while MCE's Application does not ask the Commission to set or investigate rates[62] and therefore does not meet the definition of a "ratesetting proceeding" in Rule 1.3(g), the Commission should nevertheless categorize this Application as a "ratesetting proceeding" because, as described above, the Commission has the authority to do so where a proceeding does not clearly fit into any of the categories as defined in Rules 1.3(a), (b), (f) and (g).[63]

F. Need for Hearing - Rule 2.1(c)

MCE has made efforts to provide a sufficient record via its Application materials to obviate the need for evidentiary hearings, and does not recommend hearings at this time. If the need for

---

[62] EE applications filed by investor-owned utilities are generally categorized as "ratesetting" proceedings under Rule 1.3(g) because those proceedings require the Commission to approve rates that collect the funds necessary to pay for EE programs. In contrast, MCE's EE Application does not require the Commission to set rates because, while MCE's Application has a ratesetting impact, MCE does not itself collect revenue for Commission-authorized EE programs and therefore does not request that the Commission set rates.

[63] Rule 7.1(e)(2).

hearings arises, MCE requests that the resulting hearing schedule allow the Commission to render a final decision on this application with sufficient time to start implementing its 2024-2031 Business Plan and 2024-2027 Portfolio Plan at the start of 2024. Section VII.E, below, sets forth a proposed schedule for the consideration of EE applications.

G. Issues to be Considered - Rule 2.1(c)

MCE's Application requests that the Commission approve MCE's 2024-2031 Business Plan and 2024-2027 Portfolio Plan. Approval will enable MCE to successfully and sustainably provide a comprehensive EE portfolio to its member communities. MCE also requests that the Commission authorize funding for MCE's PeakFLEX Market program for PYs 2024-2027 in this proceeding.

H. Proposed Schedule - Rule 2.1(c)

MCE proposes the following schedule for the consideration of EE applications:

Application Filed	**March 4, 2022**
Protests or Responses	**April 7, 2022**
Replies to Protests or Responses	**April 21, 2022**
Prehearing Conference	**May 2022**
Workshops (if needed)	**July 2022**
Testimony of Interested Parties	**September 19, 2022**
Rebuttal Testimony/Replies to Comments	**October 19, 2022**
Evidentiary Hearings (if needed)	**November 18, 2022**
Opening Briefs	**January 16, 2023**
Reply Briefs	**February 15, 2023**
Proposed Decision	**August 2023**
Final Decision	**September 2023**
Cost-Effectiveness Workshops	**March 2024**

This schedule would satisfy the Commission's requirement that ratesetting proceedings be resolved within 18 months or less.

I. Articles of Incorporation - Rule 2.2

MCE is a CCA operating as a joint powers authority (JPA) organized under California law.

MCE commenced operations as a JPA on December 19, 2008. MCE is engaged in the provision of electric generation services under the authority granted in Cal. Pub. Util. Code § 366.2 and offers EE programs under the authority granted in Cal. Pub. Util. Code § 381.1. A copy of MCE's current Amended JPA, amended November 19, 2020, is available on MCE's website.[64]

J. Rule 3.2 Requirement

The requirements listed in Rule 3.2 do not apply to this application because MCE does not request authority to increase rates or to implement changes that would result in increased rates. IOUs perform revenue collection for MCE's EE programs and typically provide the materials described in Rule 3.2 in their EE applications. As discussed above in section VII.B (Categorization – Ratesetting), MCE does not directly collect revenue for its EE programs. Thus, MCE does not propose specific rate changes in this Application. The requirements of Commission Rule 3.2 cannot therefore reasonably apply to this Application.

K. Notice and Service - Rule 1.9

A copy of the Application and supporting testimony are being served on the parties of record in R.13-11-005, Commissioner Shiroma, and Administrative Law Judges Fitch and Kao.

L. List of Supporting Documents

MCE includes several documents to support this application:

- Testimony of Marin Clean Energy Regarding its Energy Efficiency Business Plan, including attachments (Exhibit 1)
- Testimony of Marin Clean Energy Regarding its Energy Efficiency Portfolio Plan, including attachments (Exhibit 2); and

---

[64] Marin Energy Authority Joint Powers Agreement, effective December 19, 2008, as further amended by Amendment No. 15 dated November 19, 2020, *available at:* https://www.mcecleanenergy.org/wp-content/uploads/2020/12/MCE-JPA-Agreement-37-Communities.pdf.

- Appendices A-E to Testimony of Marin Clean Energy (Exhibit 3).

Appendix A is an Excel spreadsheet and will be made available online. A Notice of Availability included in Exhibit 3 will provide a link to Appendix A.

VII. CONCLUSION

For the reasons described in this Application, and in MCE's testimony in support of this application, MCE respectfully requests that the Commission expeditiously approve this Application and grant the following relief:

- Approve MCE's 2024-2027 EE Portfolio Plan described in Exhibit 2 of MCE's testimony, and associated annual budgets described in Exhibit 2, Chapter 1 of MCE's testimony;
- Approve MCE's 2024-2031 EE Business Plan described in Exhibit 1 of MCE's testimony, and associated budget cap described in Exhibit 1, Chapter 2 of MCE's testimony;
- Approve funding for MCE's Peak FLEXmarket program for program years 2024-2027, consistent with the budget described in Exhibit 1, Chapter 2 of MCE's testimony in support of this application;
- Bolster the Cost Effectiveness Tool and the California Energy Data and Reporting System;
- Modify the Cost Effectiveness Tool to appropriately calculate the impacts of demand reduction measures;
- Establish clear deadlines for updating technical tools and templates;
- Direct MCE and PG&E to exchange DR program participation data on a quarterly basis;
- Continue to evaluate the future use of the PAC test instead of the TRC test to evaluate the cost-effectiveness of the Resource Acquisition segment, and;
- Develop non-energy benefits as an indicator for the equity segment of EE portfolios.

Respectfully submitted,

By: */s/ Jana-Kopyciok-Lande*__________
Jana Kopyciok-Lande

Jana Kopyciok-Lande
Strategic Policy Manager
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6044
E-Mail: jkopyciok-lande@mceCleanEnergy.org

*/s/ Mad Stano*_______________
Mad Stano

Mad Stano
Policy Counsel
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6024
E-Mail: mstano@mceCleanEnergy.org

DATED: March 4, 2022

VERIFICATION

I, the undersigned, say:

I am an officer of Marin Clean Energy, a Community Choice Aggregator, and am authorized to make this verification on its behalf. The statements in the foregoing APPLICATION OF MARIN CLEAN ENERGY FOR APPROVAL OF 2024-2031 ENERGY EFFICIENCY BUSINESS PLAN AND 2024-2027 ENERGY EFFICIENCY PORTFOLIO PLAN are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on March 3, 2022, at San Rafael, California.

DocuSigned by:
Dawn Weisz
A59878416EBC4F8...
Dawn Weisz
Chief Executive Officer