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Empowering Our Clean Energy Future
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August 1, 2025

Mr. Drew Bohan
Executive Director
California Energy Commission
715 P Street
Sacramento, CA 95814

RE: MCE's Revised Load Management Standards Plan

Dear Mr. Bohan,

In accordance with Section 1623.1(a)(3)(B) of the California Energy Commission's Load Management Standards (LMS), MCE hereby submits its Revised LMS Plan to the CEC's Docket Number 23-LMS-01.

MCE submitted its original LMS Plan to this docket on June 14, 2024. In accordance with your June 19, 2025 letter requesting revisions to MCE's LMS Plan, MCE's Board of Directors adopted a Revised LMS Plan during a duly noticed Board meeting on July 17, 2025. The plan was revised to reflect recent activity by MCE's Board to advance load flexibility:

- Submitting a joint LSE proposed plan for the statewide standard RIN tool;
- Offering our own distinct dynamic EV rate pilot, the MCE Sync Dynamic Rewards Pilot; and
- Offering the CalFUSE dynamic rate pilots approved by the California Public Utilities Commission.

Enclosed is MCE's Revised LMS Plan for the CEC's final approval. If you have any questions or additional information is required, please contact Jordyn Bishop at jbishop@mcecleanenergy.org.

Sincerely,

Sabrinna Soldavini
VP of Policy
ssoldavini@mcecleanenergy.org

Enclosed:
Attachment 1: Clean - MCE's Revised LMS Plan
Attachment 2: Redline - MCE's Revised LMS Plan

MARIN CLEAN ENERGY

LOAD MANAGEMENT STANDARDS PLAN

Approved by MCE Board May 16, 2024

1 Table of Contents

2 Introduction

2.1 About MCE

Marin Clean Energy ("MCE") is California's first Community Choice Aggregation ("CCA") Program, a not-for-profit Joint Powers Authority ("JPA") that began serving customers in 2010. MCE's mission is to confront the climate crisis by eliminating fossil fuel greenhouse gas ("GHG") emissions, producing renewable energy, and creating equitable community benefits. MCE's vision is to lead California to an equitable, clean, affordable, and reliable energy economy by serving as a model for community-based renewable energy, energy efficiency, and cutting-edge clean-tech products and programs.

As a load-serving entity ("LSE") MCE provides electricity generation service to approximately 580,000 customer accounts. These accounts represent more than one million residents and businesses across four Bay Area counties.[1] MCE procures for annual retail sales of approximately 5,729 GWh and a peak load of more than 1,240 MW.

MCE provides service to approximately 87 percent of eligible customers within its service area, which is depicted below in Figure 1. MCE is also the default generation provider for any new or relocated customers therein.

Figure 1: MCE Service Area Map

[1] MCE serves communities across Contra Costa, Marin, Napa, and Solano counties. Those communities currently receiving service include: Unincorporated Contra Costa, Marin, Napa, and Solano counties and the Cities and Towns of Concord, Danville, El Cerrito, Lafayette, Martinez, Moraga, Oakley, Pinole, Pittsburg, Pleasant Hill, Richmond, San Pablo, San Ramon, Walnut Creek, Belvedere, Corte Madera, Fairfax, Larkspur, Mill Valley, Novato, Ross, San Anselmo, San Rafael, Sausalito, Tiburon, American Canyon, Calistoga, Napa, St. Helena, Yountville, Benicia, Vallejo, and Fairfield. MCE expects service to expand to include the City of Hercules in April of 2025.

As a JPA and local government agency, MCE is governed by a 34-member Board of Directors ("Board" or "Governing Board") composed of elected representatives from MCE's member communities. MCE's Board sets policy for the agency and oversees operations, including rates and procurement planning. Through these representatives, MCE is controlled by and accountable to the communities MCE serves.

MCE was formed to empower its member communities to choose the generation resources that reflect their specific values and needs. As a mission-driven local government agency, MCE works toward the following:

- Reducing GHG emissions and accelerating the supply of clean energy being delivered to and used on the grid;
- Developing community programs and local energy projects to expand access to competitively priced renewable energy and energy efficiency programs for all customers;
- Creating economic and workforce benefits associated with renewable energy and energy conservation programs; and
- Leveraging energy and conservation spending to promote more equity throughout MCE's communities and California.

2.2 Load Management Standards

In Docket Number 21-OIR-03 the California Energy Commission ("CEC") adopted Revised Load Management Standards ("LMS" or "Standards"). The amendments to the LMS, which became effective on April 1, 2023, are intended to form the foundation for a statewide system of time and locational dependent signals that can be used by automation-enabled devices to encourage load flexibility on the electric grid. Simply, the Standards are intended to encourage automated load shifting of electricity to off-peak hours.

To accomplish the goals of the LMS, the regulations request California's large CCAs,[2] investor-owned utilities ("IOUs"), and large publicly owned utilities ("POUs") to offer customers access to rate-structures and/or programs that allow automated responses to prices or other grid signals to manage and optimize their energy use.

Specifically, the LMS request large CCAs to (1) develop and propose marginal cost-based rates that vary at least hourly[3] or, (2) if the Board finds that implementing marginal cost-based hourly rates would not materially reduce peak load, be technologically feasible, and/or be cost-effective, offer a load flexibility program that allows at least one option for automating response to the CEC's Market Informed Demand Automation Server ("MIDAS") signals for customer classes where MCE's Board determines such a program would materially reduce peak load and be cost-effective. For the purposes of this plan, MCE will refer to marginal cost-based rates that vary at least hourly as defined in the LMS as "hourly" or "dynamic" rates.

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[2] The LMS define Large CCAs as any CCA that provides in excess 700 GWh of electricity to customers in any calendar year.

[3] Section 1623.1(b)(1) of the LMS define a marginal cost-based rate 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, including the locational marginal cost of associated greenhouse gas emissions, on a time interval of no more than one hour.

2.2.1 MCE LMS Plan and Board Authority

Section 1623.1(a) requests each large CCA submit a plan outlining how it plans to meet the objectives of the LMS to its Board by April 1, 2024.

As a large CCA that shares the goals and objectives of the LMS to better align demand of electricity with periods of high renewable energy supply and encouraging automated load shifting away from peak periods, MCE submits this plan to the Board for approval. [4] The purpose of this plan is to identify the steps and activities MCE plans to voluntarily undertake which align with the goals of the LMS.

MCE notes that nothing in this plan overrides or supersedes MCE's Board's sole authority as the governing and rate-making body of MCE.[5] Nothing in this plan implies any jurisdictional authority of the CEC over MCE's rates and rate programs. MCE is currently voluntarily taking reasonable steps that meet the standards within the LMS regulations.

Additionally, as outlined in the LMS, MCE's Board may approve a plan, or material revisions to a previously approved plan, that delays implementation of or modifies the goals of LMS Subsections 1623.1(b)-(c), if the Board determines that despite good faith efforts implantation:

- Would result in extreme hardship to MCE;
- Would result in reduced system reliability (e.g., equity or safety) or efficiency;
- Would not be technologically feasible or cost effective; or
- Must be modified to provide a more technologically feasible, equitable, safe, or cost-effective way to achieve the LMS or plan's goals.

Accordingly, MCE submits this plan to the Board for adoption and approval to implement as outlined herein. Table 1 below provides a list of each regulatory standard or goal as outlined in the LMS and MCE's plan to meet that standard or goal at the time of this writing. As described, MCE plans to continue to offer its portfolio of current and planned load flexibility programs and time dependent rates aimed at encouraging customers to use energy in off-peak hours, and will continue to explore how it may offer new cost-effective dynamic rates, pilots, and load flexibility programs that materially reduce peak load, encourage load control through automation, and provide reliability and environmental benefits for MCE customers and the California electric grid.

[4] Consistent with Section 1623.1(a) of the LMS, MCE submitted this plan to its Board on March 29, 2024, and will submit this plan to the CEC within 30 days of Board approval.
[5] Public Utilities Code Section 366.2(c)(3) provides that CCAs retain jurisdiction for setting rates for the electricity they purchase on behalf of their communities.

Table 1: MCE LMS Roadmap

Load Management Standards Section	Standard Description	Target Date	MCE Adopted Plan to Meet Standard
§1623.1(c)	Upload existing time-dependent rates to MIDAS database.	July 1, 2023	Status: Achieved MCE plans to maintain future rates in MIDAS to the extent it is cost effective and technologically feasible. MCE cannot confirm that uploading future dynamic rates or programs to MIDAS will be cost effective or technologically feasible.
§1623.1(a)(1)	Develop and submit a plan for adoption to MCE's Board addressing how MCE plans to meet objectives of the LMS. The plan is to be considered for adoption by MCE's Board within 60 days of submission at a duly noticed public meeting.	April 1, 2024	Status: Achieved
§1623.1(a)(3)(A)	Within 30 days of adoption of the plan, submit the plan to the CEC's Executive Director.	30 Days After Board Adoption	Status: MCE will submit this plan to the CEC within 30 days of Board adoption.
§1623(c)	Within one year of LMS effective date, provide customers access to their Rate Identification Numbers on billing statements and in online accounts using both text and quick response code format.	April 1, 2024	Status: In Progress, Expected to Achieve
§1623(c)	In conjunction with the other named LSEs, develop and submit to the CEC a plan for a single statewide standard tool for authorized rate data access by third parties and the terms and conditions for using the tool. Upon CEC approval, maintain and implement the tool.	October 1, 2024	Status: In Progress MCE is engaged in and monitoring the development process for the single statewide tool.

Load Management Standards Section	Standard Description	Target Date	MCE Adopted Plan to Meet Standard
§1623.1(b)(3)	Submit to the CEC a list of load flexibility programs deemed cost effective by MCE. The portfolio of programs should provide at least one option to automate response to MIDAS signals for each customer class where MCE's Board has determined such a program would materially reduce peak load.	October 1, 2024	Status: In Progress MCE cannot determine that such a program will materially reduce peak load for any customer class. MCE will submit a list of programs deemed cost effective to the CEC but does not expect to include an option to automate response to MIDAS signal at this time.
§1623.1(a)(3)(C)	Submit annual reports to the CEC demonstrating implementation of the plan, as approved by the Board.	Annually	Status: In Progress MCE will submit annual reports beginning one year after the adoption of this plan.
§1623.1(b)(2)	Submit at least one marginal cost-based rate to MCE's Board for approval for any customer class(es) where such a rate will materially reduce peak load. An Information copy of the tariff applications will be provided to the CEC.	July 1, 2025	Status: In Progress At this time MCE cannot determine that such a rate or will provide material, incremental reductions to peak load or be cost effective for any customer class. However, MCE is interested in collecting the data necessary to make such determinations and will continue to explore options to offer dynamic rate pilots in its service territory. MCE therefore recommends the Board modify this standard and determine that MCE may, but is not required to, propose such a rate or program by the target date. MCE will continue to evaluate and address in its next plan iteration and any annual reports.
§1623.1(b)(4)	Offer each customer voluntary participation in either a marginal cost-based rate, if approved by the Board, or a cost-effective load flexibility program.	July 1, 2027	Status: To be determined by future Board direction. MCE notes that this target date is after the next review of MCE's LMS is expected to be completed. As such, MCE will likely provide an update in its next LMS plan as appropriate.

Load Management Standards Section	Standard Description	Target Date	MCE Adopted Plan to Meet Standard
§1623.1(b)(5)	Conduct a public information program to inform and educate affected customers on why marginal cost-based rates or load flexibility programs and automation are needed, how they will be used, and how these rates and programs can save customers money.	No Target Date Specified	Status: To be determined by future Board direction and future adoption of dynamic rates or load-modifying programs.
§1623.1(a)(1)(C)	Review the plan at least once every three years after the plan is adopted and submit a plan update to the Board if there is a material change.	Once Every Three Years	Status: MCE will review its LMS plan at least once every three years following the date of adoption.

3 Access to Price Signals

3.1 Time-Dependent Rate Submission to MIDAS

Adopted LMS Amendments Section 1623.1(c) requests each Large CCA upload existing time dependent rates to the MIDAS database by July 1, 2023. On June 1, 2023, the CEC issued Order No. 23-0531-109 approving an extension for CCAs to upload time-dependent generation rates by August 1, 2023, and any remaining time-depending rates with rate modifiers by October 1, 2023. Large CCAs are also asked to upload any new time-dependent rates or changes to existing rates, prior to the effective date of that rate.

3.1.1 Existing Rates Upload

MCE successfully uploaded all of its 70 active Light Green service rates by the CEC's target date of August 1, 2023, and uploaded its Deep Green service rates by the target date of October 1, 2023, to include time-dependent rates with additional modifiers. A complete list of rates uploaded to MIDAS and their associated Rate Identification Numbers ("RIN") is included in Appendix A.

The period covered by the initial upload spanned between three and six months, due to data limitations of the MIDAS system. As such, MCE has made subsequent uploads to keep rates current in MIDAS:

1. In October 2023, MCE uploaded additional intervals to ensure all rates were up-to-date through December 31, 2023.

2. In November 2023, MCE uploaded additional intervals for all rates through May 1, 2024.[6]

3.1.2 Future Rates Upload

To the extent that uploading future rates is feasible and cost effective, MCE plans to maintain its generation rates in MIDAS so that customers and their devices may access them for device automation. However, MCE notes that if hourly rates are approved by MCE's Board, daily uploads of such rates to MIDAS will present significant challenges. Given the current structure of MIDAS and the lack of funding for LSEs to develop systems, processes, and improvements to MIDAS, MCE cannot at this time find that it is cost effective or feasible to maintain current and accurate rates for any future hourly rate offerings in MIDAS.

Nonetheless, MCE is engaged in and monitoring the Demand Flexibility Proceeding at the California Public Utilities Commission ("CPUC") and is committed to working with the CEC, CPUC, and other stakeholders to help customers automate behavioral changes in electric usage and looks forward to further discussion on how MIDAS may be updated and/or will interact with future rate platforms or repositories yet to be developed such as a CPUC approved Price Machine.

MCE recommends that any future rate repositories be equipped to provide composite rates if the goal is to provide customers with a composite or total real-time rate signal. As a CCA, MCE's Board has sole authority over its customers' generation rate component but has no authority to determine the distribution or transmission rate components of its customers' rates. Any distribution and transmission rate components charged to MCE customers are charged by Pacific Gas & Electric Company ("PG&E"). As such, MCE only plans to upload generation rate components to MIDAS and cannot take responsibility for, be required to calculate, or be required to upload marginal cost rates for rate components and myriad PG&E programs that it has no control over.

3.2 Plan to Provide Rate Identification Number(s) on Customer Billing Statements and Online Account Using Both Text and QR Code

Adopted LMS Amendments Section 1623(c)(4) requests each Large CCA to provide customers with access to their RIN on customer billing statements and online accounts using both text and quick response ("QR") or similar machine-readable digital code by April 1, 2024.

MCE customers receive their consolidated billing statements from PG&E. MCE provides itemized charges to PG&E through Electronic Data Interchange ("EDI") transactions. Therefore, MCE is reliant on PG&E to develop its EDI system to accept MCE RINs and display them on customer bills.

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[6] As of this writing, six of MCE's Light Green rates are not current in the MIDAS system. These rates serve a small number of large Commercial & Industrial and EV customers with legacy 12p-6p peak periods. Upload attempts are rejected with the message, "An error has occurred." MCE reached first reached out to CEC staff on November 30, 2023, and has had numerous, ongoing communications with CEC staff on this matter. The issue appears to reside with MIDAS, and not with MCE. CEC Staff has indicated they are aware of the issue, that it is not isolated to MCE and the CEC is working to resolve the issue. MCE will continue to engage and collaborate with the CEC in good faith to fix this issue.

CCAs have been working with PG&E to utilize PG&E's billing transactions to include a CCA specific RIN on customers' bills. MCE will supply MCE's RIN mapping table to PG&E who will then include it within the code and display customers' RINs on the generation portion of their bills. This interpretation has also been corroborated by PG&E in recent CPUC Advice Letters seeking approval to modify customers' bill presentations to include RINs and QR codes.

On January 16, 2024, PG&E filed Advice Letter 7136-E at the CPUC outlining the process it is undertaking to provide RINs on customer bills. As outlined by PG&E in its second supplemental Advice Letter 7136-E-B filed on March 1, 2024, customers on time-dependent rates will have their bills updated to include a QR code and the customer's RIN in the top right-hand corner of their bill, which can then be scanned to program a customer's device(s). PG&E notes that RINs will be presented the same way on both bundled and unbundled (CCA and Direct Access) customers' bills.

3.3 Plans and Current Participation in the Development of Single Statewide RIN Access Tool – *Amended July 2025*

Adopted LMS Amendments Section 1623(c)(1)-(3) requests all LSEs named in the Standards to work together to develop a plan for a single statewide standard tool for authorized rate data access by third parties, along with a single set of terms and conditions for third parties using the tool by October 1, 2024. The tool is to provide the customers' RINs, provide eligible RINs, enable switching to an available rate by an authorized third party, incorporate applicable cybersecurity measures, minimize enrollment barriers, and be accessible in digital, machine-readable format.

MCE is monitoring and engaging in the process with the other regulated LSEs to develop a Single Statewide RIN Access Tool pursuant to Adopted LMS Amendments Section 1623(c). A proposed plan for the tool was submitted to the CEC for review on October 1, 2024. MCE will continue to collaborate with other parties and the CEC towards the implementation and maintenance of the tool in a timely manner subject to the tool's approval by the CEC. MCE is unable to specifically identify the full scope and budget of integration of work; commit resources; or review, identify, and plan internal infrastructure needs until the Single Statewide Standard RIN Access Tool's scope has been designed and approved by the CEC.

4 MCE Rates and Dynamic Rate Considerations

Adopted LMS Amendments Section 1623.1(a)(1) requests each large CCA to develop a plan that evaluates the cost-effectiveness, equity, technological feasibility, benefits to the grid, and benefits to customers of dynamic rates for each customer class. After evaluating dynamic rates, the CCA may instead propose and evaluate specified programs and/or delay or modify its implementation of the LMS.

Adopted LMS Amendments Section 1623.1(b)(2) requests MCE apply to its rate-approving body for approval of at least one dynamic rate by July 1, 2025. The LMS state MCE is to apply for approval only of a dynamic rate only for those customer classes for which the Board determines such a rate will materially reduce peak load.

Adopted LMS Amendments Section 1623.1(b)(4) requests each CCA to offer to each of its electricity customers voluntary participation in either a dynamic rate developed according to Section 1623.1(b)(2), if such rate is approved by the Board, or a cost-effective load flexibility program that allows automated response to MIDAS signals for each customer class the Board determines such a program would materially reduce peak load July 1, 2027.

This section provides an overview of MCE's current time-dependent rates and its plan to evaluate and develop dynamic rates as stated in the LMS.

4.1 Overview of MCE's Current Time-Dependent Rate Offerings

MCE currently offers several options for time-dependent or Time-Of-Use ("TOU") pricing, consistent with the options available to the broader PG&E service area. Approximately 66 percent of MCE households are on time-dependent rates. Current residential rate options are displayed in the table below.

Table 2: Current MCE Residential Rate Offerings[7]

MCE Residential Rate	Description of Rate Periods
E-1	Flat Rate Pricing, not time dependent
E-TOU-C - Default Time-of-Use	Utilizes 4pm-9pm peak rates every day
E-TOU-D - Time-of-Use	Utilizes 5pm-9pm peak rates on non-holiday weekdays only
ELEC - Time-of-Use for Qualified Electric Technologies	Utilizes lower rates from 12am-3pm
EV2 - Time-of-Use for Electric Vehicles	Utilizes lower rates from 12am-3pm

Additionally, MCE continues to provide limited service to legacy residential rate schedules that are no longer available to new customers:

- E-TOU-B - Time-of-Use: Utilizes 4pm-9pm peak rates on non-holiday weekdays only; and
- EV - Time-of-Use for Solar Customers with Electric Vehicles: Utilizes lower rates from 11pm-2pm.

MCE also offers a wide range of options for time-dependent pricing for non-residential customers as depicted in Table 3 below. Except in rare circumstances like street lighting, non-residential service is entirely billed according to time-dependent pricing. All of MCE's

[7] A complete list of MCE Residential rates can be found at https://www.mcecleanenergy.org/rates/.

non-residential rates have 4pm-9pm daily peak and seasonal rates, except where noted otherwise.

Table 3: Current MCE Non-Residential Rate Offerings[8]

MCE Non-Residential Rates	Description of Rate Periods
B-1 - Small General Service	Utilizes six TOU periods (three in the Summer and three in the Winter)
B-1ST - Small General Service Plus Storage	Utilizes seven TOU periods (three in the Summer and four in the Winter)
B-6 - Small General Service	Utilizes five TOU periods (two in the Summer and three in the Winter) and stronger pricing signals relative to rate schedule B-1
B-10 - Medium General Service	Utilizes six TOU periods (three in the Summer and three in the Winter) and three voltage levels with discrete rates
B-19 - Medium General Service	Utilizes six TOU periods (three in the Summer and three in the Winter), TOU and seasonal based demand charges, and three voltage levels with discrete rates
B-19 Option R - Medium General Service for Solar	Utilizes six TOU periods (three in the Summer and three in the Winter), no demand charges, and three voltage levels with discrete rates
B-20 Option R - Large General Service for Solar	Utilizes six TOU periods (three in the Summer and three in the Winter), no demand charges, and three voltage levels with discrete rates
BEV - Commercial EV Charging	Utilizes three TOU periods, no seasonality, and three voltage levels with discrete rates
AG-A - Small Agriculture	Utilizes four TOU periods (two in the Summer and two in the Winter), and uses a 5pm-8pm peak pricing period

[8] A complete list of MCE Non-Residential rates can be found at https://www.mcecleanenergy.org/commercial-rates/.

MCE Non-Residential Rates	Description of Rate Periods
AG-B - Medium Agriculture	Utilizes four TOU periods (two in the Summer and two in the Winter), 5pm-8pm peak pricing period
AG-C - Large Agriculture	Utilizes four TOU periods (two in the Summer and two in the Winter), 5p-8p peak, summer peak demand
AG-F - Flexible TOU Agriculture	Utilizes AG-A/AG-B/AG-C variations as above, with two designated 24-hour off-peak days
SB - Standby Service	Utilizes six TOU periods (three in the Summer and three in the Winter), a reservation charge per kW, and three voltage levels with discrete rates
SL-1 - Street, Highway, and Outdoor Lighting	This rate is not time dependent
TC-1 - Traffic Control Service	This rate is not time dependent

MCE also continues to offer limited service to legacy non-residential rate schedules without a 4pm-9pm peak. Eligibility is determined by PG&E according to tariffs approved by the CPUC. These rates have a 12pm-6pm peak and seasonal rates, except where otherwise noted, and have weak pricing signals and are of limited significance to MCE's portfolio. Only 6.5 percent of MCE customers – almost entirely small commercial accounts – are served by these rates.

Table 4: MCE Legacy Rates

MCE Legacy Rates	Description of Rate Periods
A-1 - Small General Service	This is a non-TOU rate
A-1X - Small General Service	Utilizes five TOU periods (three in the Summer and two in the Winter)
A-6 - Small General Service	Utilizes five TOU periods (three in the Summer and two in the Winter)
A-10 - Medium General Service	This is a non-TOU rate but includes three voltage levels with discrete rates

MCE Legacy Rates	Description of Rate Periods
A-10X - Medium General Service	Utilizes five TOU periods (three in the Summer and two in the Winter) and three voltage levels with discrete rates
E-19 - Medium General Service	Utilizes five TOU periods (three in the Summer and two in the Winter), demand charges, and three voltage levels with discrete rates
E-20 - Large General Service	Utilizes five TOU periods (three in the Summer and two in the Winter), and three voltage levels with discrete rates
E-20 Option R - Large General Service for Solar Customers	Utilizes five TOU periods (three in the Summer and two in the Winter), and three voltage levels with discrete rates
AG-1 - Small Agricultural Service	This is a non-TOU rate
AG-4-A - Time-of-Use Agricultural Service	Time-of-Use Agricultural Service: Includes four TOU periods (two in the Summer and two in the Winter) and a connected load charge
AG-4-B - Time-of-Use Agricultural Service	Utilizes four TOU periods (two in the Summer and two in the Winter) and a maximum demand charge
AG-4-C - Time-of-Use Agricultural Service	Utilizes five TOU periods (three in the Summer and two in the Winter) and a peak demand charge
AG-5-A - Time-of-Use Agricultural Service	Utilizes four TOU periods (two in the Summer and two in the Winter) and a connected load charge
AG-5-B - Time-of-Use Agricultural Service	Utilizes four TOU periods (two in the Summer and two in the Winter) and a maximum demand charge
AG-5-C - Time-of-Use Agricultural Service	Utilizes five TOU periods (three in the Summer and two in the Winter) and a peak demand charge
AG-R - Time-of-Use Agricultural Service with Off Peak Days	Utilizes four TOU periods (two in the Summer and two in the Winter), two day-

MCE Legacy Rates	Description of Rate Periods
	of-week options, two service levels, and connected load or demand charges
AG-R - Time-of-Use Agricultural Service with Variable Peak	Utilizes four TOU periods (three in the Summer and two in the Winter), three peak hour options, two service levels, and connected load or demand charges
S - Standby Service	Utilizes five TOU periods (three in the Summer and two in the Winter), reservation charge per kW, and three voltage levels with discrete rates

MCE also offers two energy supply programs that are charged or credited to the customer's energy bill but separate from each customer's electric rate schedule:

- Deep Green Service: This program allows customers to choose 100 percent renewable energy content and includes a $0.01/kWh flat adder to all rates.
- Disadvantaged Communities Green Tariff ("DAC-GT"): This program allows eligible customers in disadvantaged communities to choose 100 percent renewable energy content and receive a 20 percent total bill discount.

4.2 Dynamic Rates Evaluation – *Amended July 2025*

MCE strongly appreciates and supports the LMS' goals to help encourage customers to shift energy consumption away from peak periods to minimize costs, improve reliability, and better align renewable energy supply and demand. MCE also agrees that two tools that can be utilized to encourage such a shift are flexible rate designs and automation technology.

Consistent with the adopted LMS, in this section MCE outlines its plan to evaluate future dynamic marginal cost-based rate offerings for its customers and provides an initial evaluation of the cost-effectiveness, equity, technological feasibility, and benefits of dynamic rates.

As a CCA, MCE's Board has sole authority over its customers' generation rate component and no other entity, including the CEC or CPUC, has the authority to set generation rates for MCE customers. Similarly, this means that MCE does not have authority to determine the distribution or transmission rate components of its customers. Any distribution and transmission rate components charged to MCE customers are determined and charged by PG&E, as approved by the CPUC and/or Federal Energy Regulatory Commission. As such, any dynamic or hourly rates adopted by MCE's Board will be generation-only. MCE and its Board cannot take responsibility for, or be required to calculate, rates for components that it has no control over such as distribution and transmission rate components.

MCE understands that there may be value in dynamic rates or dynamic rate pilots, and is currently offering all the dynamic rate pilots approved by the CPUC for PG&E's service area[9] as well as offering its own, distinct dynamic EV rate pilot to its customers, MCE Sync Dynamic Rewards.[10] These pilots should allow MCE to collect data to evaluate the cost-effectiveness, equity, feasibility, and customer and grid benefits of such rates to inform MCE's future rate designs and offerings. Generally, MCE notes that it has a preference to create and offer MCE specific rates, pilots, and programs that can be uniquely tailored and administered by MCE to meet the needs of its customers, which may be distinct from other regions of PG&E's service area and rely on MCE's significantly clean and GHG-free portfolio in the California Independent System Operator markets.

In evaluating whether to offer future additional dynamic rates and/or pilots, MCE plans to evaluate portfolio-based cost-effectiveness, technical feasibility, equity, and benefits to MCE and its customers and the environment. MCE will consider what pricing options, if any, offer cost-effective and material, incremental, benefits over current rate and load flexibility offerings. Offering dynamic rate pilots should provide necessary and useful data to evaluate and determine the appropriateness (and potential design) of future dynamic rate offerings in MCE's service area.

In the version of this plan approved by the Board on May 16, 2024, MCE found that it did not have sufficient evidence to conclude that developing and implementing dynamic rates in MCE's service area on the timeline outlined in the LMS would be cost effective or provide material incremental reductions to peak load beyond those of its current rate and programs portfolio for any customer class. The Board-approved plan found it necessary to modify Section 1623.1(b)(2)'s request for MCE to apply for approval of a dynamic rate by July 1, 2025. The Board-approved plan concluded that the timeline must be modified to ensure cost-effective implementation and that MCE Staff may, but was not required to, propose such a rate to the Board by the target date of July 1, 2025. At that time, MCE could not commit to creating such a rate for Board approval by July 1, 2025. However, MCE is interested in collecting the data necessary to make such determinations and is now offering dynamic rate pilots in its service territory. MCE began offering the MCE Sync Dynamic Rewards pilot in September 2024, and on April 4, 2025, MCE's Board approved MCE's participation in the dynamic rate pilots offered in PG&E's service area: Expanded Pilot 1, Expanded Pilot 2, and the VGI-Commercial Pilot, and therefore has met the original timeline adopted in Section 1623.1(b)(2). MCE will provide updates to its Board in its next plan iteration and any annual reports.

[9] California Public Utilities Commission Decision (D) 24-01-032 approved the expansion of two demand flexibility pilots in PG&E's service area that allow CCA participation. Under the Transportation Electrification Rulemaking 18-12-006, the CPUC further authorized PG&E's vehicle-to-grid (VGI) pilots with a dynamic rate that allow CCA participation. MCE is currently offering all three pilots to its customers.

[10] The MCE Sync Dynamic Rewards pilot allows customers the chance to receive additional savings in MCE Sync by responding to dynamic hourly price signals (based on day-ahead CAISO prices for the PG&E Default Load Aggregation Point (DLAP). Customers who enroll in the dynamic pilot will receive an enrollment bonus of $50 and then receive a monthly reward payment for allowing MCE Sync to charge their car according to the dynamic price signal.

a. Cost-Effectiveness

In determining whether to offer dynamic rates that vary at least hourly as outlined in the LMS, one evaluation factor that MCE will consider is cost-effectiveness.

MCE notes that the CEC's adopted LMS state there shall be no reimbursement to local government agencies for the costs of carrying out the Standards as the Commission has found them to be cost effective, noting that savings realized will outweigh the costs associated with implementing the programs.[11] While MCE appreciates the plain language of the LMS, MCE disagrees that the cost-effectiveness of any rates or programs could be determined before those rates or programs actually exist. At this point there exists no evidence to conclude that MCE will realize any net savings from implementing the LMS. It is too early in MCE's offering of hourly or dynamic rates or pilot programs to allow for sufficient analysis of the effectiveness (cost or otherwise) of dynamic rates in its service area. MCE has so far incurred only costs associated with the LMS and any benefits remain to be realized.

Nonetheless, MCE shares many of the CEC's stated goals in developing the LMS and is committed to encouraging customers to shift energy consumption to off-peak periods. MCE appreciates and understands that there may be significant value in dynamic rates and is interested in collecting the necessary information and data to determine if, and under what conditions, dynamic rates would be cost effective for MCE and its customers.

As of September 2024, MCE implemented an hourly rate pilot for its electric vehicle ("EV") customers, MCE Sync Dynamic Rewards.[12] MCE is also participating in, monitoring, and evaluating the status of CPUC approved PG&E dynamic rate pilots. However, without such primary data, MCE cannot at this time determine that such a rate or program will provide material incremental reductions to peak load or be cost effective for any customer class.

Significant uncertainties remain in both the cost to develop and the value MCE can reliably realize from implementing hourly rates. MCE anticipates that developing dynamic rates may result in significant costs and MCE's ability to realize the value of such rates will be determined by unknown factors like customer adoption and incremental response levels. Without robust pilot results in MCE's and PG&E's service area to perform a comprehensive analysis, MCE cannot accurately estimate development costs, the estimated total benefits, or whether those benefits would be likely to offset the costs for any customer class. Accordingly, MCE recommends the Board not require MCE to propose dynamic rate to its Board by the target date of July 1, 2025. MCE recommends the Board find that MCE may, but is not required to, propose such a rate by the target date.

MCE will continue to evaluate whether to offer future dynamic rate pilots and rates to its customers and will evaluate the results of its own pilot and the pilots in PG&E's service area. MCE will use the pilots as an opportunity to collect the data necessary to conduct its own cost-

[11] CEC Load Management Standards Section 1623.1(e).
[12] See footnote 10.

effectiveness analysis with MCE specific data, which would be used to inform future rate and program offerings as well as future iterations of MCE's LMS Plan.

In conducting such a future cost-effectiveness analysis, MCE expects to compare the benefits of the rate offering with costs of implementation. Estimated costs include but are not limited to rate development, rate and program administration, and technology costs. Estimated benefits include, but are not limited to, lower energy costs, increased load reduction, avoided energy and capacity costs, and reliability benefits. To demonstrate cost-effectiveness, the expected benefits for each rate must exceed the costs of implementation. MCE looks forward to providing updates to its Board, the CEC, and other interested parties as it moves forward.

b. Equity

Similarly to cost-effectiveness, MCE currently has no primary data sources to quantitatively speak to the equity component of offering hourly rates to its customers. MCE is committed to increasing equitable and affordable access to clean energy for its customers. While reductions in peak demand provide grid benefits to all customers and those benefits could theoretically lower power procurement costs to all customers, currently there is not clear evidence that all MCE customers will benefit from lower rates. As MCE begins to evaluate whether to offer hourly rates to all customers, several equity components will be considered including:

Equitable Access to Automation and Benefits

Customers' ability to benefit from highly differentiated rates is directly linked to their ability to respond to those rates. Customers that can automate portions of their load will be best equipped to respond to pricing signals and benefit through lower energy bills or performance-based payments. Therefore, equitable access to automation devices and technology will be critical in ensuring that all customers can benefit from these rates. As such, MCE Staff believes it is appropriate to explore ways to ensure that customers on dynamic rates can access automation technology in an equitable manner. MCE may therefore explore offering additional incentives to provide automation technology for low-income customers and/or those who live in disadvantaged communities or multi-family properties who may otherwise not be able to benefit from automated load shifting programs or dynamic rates.

Cost Shifting

Assuming any change in rate design is designed to collect the same total level of revenue from all customers (i.e. revenue requirement), any change to rate design or structure means that some customers will pay less and some customers will pay more – without any changes to their behavior.[13] This mathematical reality is often referred to as a cost shift, as costs are shifted from one group of ratepayers to another. When rate offerings are voluntary, or opt-in, there is a greater risk that customers will simply choose the rate which allows them to pay less without making any changes to their behavior. These customers who can elect to participate in a rate that will lower their costs (and shift costs to other customers within their class) without any changes in behavior can be referred to as structural benefactors.

[13] This is at least true in the short-term. However, in the long-term material reductions/changes in behavior may lower the total revenue requirement and those cost savings could be passed through to all customers.

In developing dynamic rates with the goal of encouraging customers to *change* their behavior and shift their energy consumption away from peak hours, one of MCE's goals will be to minimize the amount of cost shifting that occurs between customers, particularly due to structural benefactors. To do so, MCE will aim to ensure that customers on hourly rates are sufficiently able to respond to price signals, whether through automation and/or price signals that are strong enough to incent behavioral change.

Customer Location

With few exceptions, customers do not choose where they are located on the electrical grid. It is partly because of this fact that grid infrastructure and energy costs have historically been spread, or averaged, across all customers. For example, rural customers have not been charged different prices for energy than city dwelling customers and MCE customers in Concord have not paid more than MCE customers in San Rafael, despite the potential differences in costs to serve those customers at any point in time (for example, due to local grid constraints). With a move to dynamic rates and advances in technology, it may be possible to charge customers in the same rate class and on the same tariff at different rates at any point in time given their location on the grid.

In both the CEC's LMS Rulemaking and the CPUC's Demand Flexibility Proceeding, there has been discussion on the level of locational granularity that should be applied to hourly or sub-hourly rates. While MCE and others are likely to first utilize hourly rates that do not vary at a level more granular than the Default Load Aggregation Point, there has been discussion of rates that vary at more granular levels, such the circuit or transformer level. Essentially, this means that the level of local grid constraint can affect the rates a customer in that area pays for electricity. MCE believes this is an important equity concern that cannot be overlooked.

Local grid constraints vary based on grid infrastructure, design, and capacity constraints that are generally outside of any individual customer's control. The more locational granularity in rates, the more potential there is for equity issues to arise. To address this issue, evaluation should be done to ensure that dynamic pricing based on localized grid constraints does not particularly burden low-income residents or those in disadvantaged communities. MCE does not currently have data on how more granular locational variation in rates may impact equity but urges all California LSEs as well as the CEC and CPUC to work to ensure that certain customers are not unfairly harmed by future rate design simply due to their location on the grid.

c. Technological Feasibility

MCE expects that it is technically feasible to offer a dynamic hourly generation rate option by July 1, 2027, as outlined in the LMS, contingent upon PG&E providing revenue quality billing data to MCE on an hourly level or developing a reliable workaround. Current PG&E billing transactions do not include the hourly interval data which would be matched against hourly dynamic prices. MCE hopes that as PG&E develops CPUC approved hourly pricing pilots, this data will become available.

MCE notes that even if dynamic rates are technically feasible, daily rate uploads to MIDAS will need to be supported by the development of new systems, which may delay or otherwise impede offering dynamic rates in the near term. The limitations of the current MIDAS system and the lack of funding for LSEs to develop systems for interacting with MIDAS may mean that it will not be cost effective or feasible to maintain dynamic rates in MIDAS at this time.

d. Benefits to the Grid and Customers

MCE will also consider benefits to the grid and benefits to customers in its evaluation of dynamic rates. Assuming material changes in energy consumption behavior by customers, potential grid benefits resulting from hourly rates include but are not limited to reliability benefits, deferred, and reduced grid infrastructure investments, and environmental benefits.

Potential direct customer benefits include, but are not limited to, lower energy expenditures, reliability benefits, and theoretically lower rates – assuming material reductions to peak load that result in lower overall energy costs and reduced capacity and compliance costs. MCE does not currently have the data to quantify benefits to the grid and customers resulting from offering hourly rates in its service territory. MCE plans to continue to gather data on this topic and will update this section in future iterations of its plan and annual reports.

4.3 Dynamic Rate Development and Application Plan – *Amended July 2025*

Adopted LMS Amendments Section 1623.1(b)(2) of the LMS requests MCE and other Large CCAs apply to its rate-approving body for approval of at least one dynamic rate by July 1, 2025. The LMS state MCE should apply for approval of a dynamic rate only for those customer classes for which the Board determines such a rate will materially reduce peak load. This section outlines how MCE plans to work toward this goal.

MCE has been, and plans to remain, actively engaged in dynamic rates discussions and proceedings at the CPUC and CEC. To date, MCE has committed considerable staff time, which amounts to significant and material cost to MCE, to these efforts, including making staff available to attend all noticed CEC LMS working group meetings and engaging in the CPUC's Demand Flexibility proceeding. Additionally, MCE is conducting research internally and in collaboration with external partners on how it might best design and offer dynamic rates in the future.

MCE is committed to exploring options for offering dynamic rate offerings to customers, but at this time cannot determine that such rates would provide material incremental reductions to peak load, provide other material benefits to MCE or its customers, or be cost effective for any customer class. In evaluating future potential dynamic rates MCE will consider whether or how any dynamic rate is expected to: 1) drive behavioral change; 2) be cost effective; 3) impact equity outcomes; and 4) provide reliable incremental benefits relative to MCE's current rate offerings.

As of September 2024, MCE began offering a dynamic rate pilot, MCE Sync Dynamic Rewards, for its electric vehicle ("EV") customers. MCE is also participating in, monitoring, and evaluating the status of CPUC approved PG&E dynamic rate pilots. However, without such primary data, MCE cannot at this time determine that such a rate or program will provide material incremental reductions to peak load or be cost effective for any customer class.

Significant uncertainties remain in both the cost to develop and the value MCE can reliably realize from implementing hourly rates. MCE anticipates that developing dynamic rates may result in significant costs and MCE's ability to realize the value of such rates will be determined by unknown factors like customer adoption and incremental load shifting response levels. Without robust pilot results in MCE's and PG&E's service area to perform a comprehensive analysis, MCE cannot accurately estimate development costs, the estimated total benefits, or whether those benefits would be likely to offset the costs. Accordingly, MCE recommends the Board not require MCE to propose a dynamic, hourly marginal cost-based rate, to its Board by the target date of July 1, 2025. MCE recommends the Board modify the request in LMS Section 1623.1(b)(2) that MCE propose dynamic rates by July 1, 2025, and declare that MCE may, but is not required to, propose such a rate to the Board for approval by July 1, 2025.

MCE will continue to evaluate if and how it may offer dynamic rates to its customers and will provide updates to its Board in its next plan iteration and any annual reports, and looks forward to continuing conversation and collaboration with stakeholders on possible pilot design, including how best to collect data that will effectively illustrate the costs and benefits of different dynamic rate structures and incorporate rates into MIDAS.

Additionally, LMS Section 1623.1(b)(4) requests MCE offer customers voluntary participation in either a dynamic rate, if approved by the Board, or a cost-effective load flexibility program by July 1, 2027. MCE notes that its offerings as of July 1, 2027, cannot be known at present, and the future timeline for deployment of future rate and program offerings will be dependent on future Board guidance and approval.

MCE plans to continue to provide updates to its Board as well as the CEC, as outlined in the LMS, and will further address the details of rate design and infrastructure needs as they become available.

5 Load Flexibility Programs

Adopted LMS Amendments Section 1623.1(b)(3) of the LMS requests MCE submit a list of cost-effective load flexibility programs to the CEC Executive Director by October 1, 2024. The portfolio of load flexibility programs is to provide at least one option to automate response to MIDAS signals for every customer class where such a program is determined by the Board to materially reduce peak load. If MCE's Board does not approve of and offer dynamic rates by July 1, 2027, the Standards state that MCE can meet the goals of the LMS by offering voluntary participation in a cost-effective MIDAS-integrated load flexibility program.

This section of MCE's Plan provides an overview of MCE's current load flexibility programs and addresses how MCE will evaluate and propose specified programs on the timeframes set forth in the LMS.

5.1 Overview of MCE Load Flexibility Programs

Residential Programs

MCE Sync

MCE Sync is an MCE-funded Automated Load Management program that utilizes a smart charging app to reduce EV owner's charging load during peak times, while also seeking to align

EV charging load with high-solar daytime hours.[14] MCE began offering MCE Sync to eligible customers in 2021 and the program offers customers a flat monthly credit for participating in events.

Through 2023, MCE Sync had approximately 2,200 enrolled MCE customers who charge their EVs at home via a software platform which delivers direct load control of EV charging using vehicle telematics and networked electric vehicle supply equipment. To date, the program has shifted 90 percent of EV charging events out of the 4 pm – 9 pm window. An analysis of program data through May 2022 showed that customers saved an average of $10 shifting charging to off-peak hours.

MCE Sync does not currently have rates associated with events. MCE Staff are currently exploring the possibility of expanding the program in MCE's service area, including integrating dynamic pricing elements into future program offerings.

Peak FLEXmarket

MCE's Peak FLEXmarket program is a market-driven demand flexibility program that assigns an hourly value to measured, behind-the-meter ("BTM") impacts.[15] Peak FLEXmarket is aimed at shifting load away from peak periods and provides customers with direct payments for measured load shedding or shifting during events, based on deviations from their individual baseline.

Peak FLEXmarket has successfully engaged new aggregators who have not participated in demand response, as well as program partners who have traditionally been confined to energy efficiency project development by presenting a value proposition for load flexibility. This program is a framework with the tools to measure and value hourly reductions in energy use and is technology agnostic.

Richmond Virtual Power Plant (VPP) Pilot

MCE is working to launch an innovative VPP pilot in Richmond, California, which will provide bill savings and increase local grid reliability, safety, and efficiency for low-income residents as part of Richmond's Advanced Energy Community project.[16] The VPP pilot includes $8 million in funding from the CEC and will provide a suite of clean distributed energy resources ("DERs") targeting low-income households in Richmond for dispatchability, flexibility, and resiliency purposes.

MCE's Richmond VPP Pilot is expected to provide significant bill savings for customers and significant local and grid benefits. MCE currently expects the pilot to launch in 2025.

Residential Efficiency Market

MCE's Residential Efficiency Market program is focused on incentivizing customers to install measures that can help reduce peak load.[17] Customers can receive a 20 percent upfront cash

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[14] *See* https://www.mcecleanenergy.org/mce-sync/.
[15] *See* https://www.mcecleanenergy.org/peak-flexmarket/.
[16] *See* http://mcecleanenergy.org/vpp.
[17] *See* https://www.mcecleanenergy.org/flexmarket/.

payment for the forecasted value of their energy efficiency projects and additional payments for metered savings of those energy efficiency projects.

Solar Storage Credit

MCE's Solar Storge Credit program is aimed at encouraging customers to discharge their energy storage systems from 4-9pm daily.[18] To be eligible for the credit, customers must be enrolled in a time-of-use rate, automate their battery to discharge from 4-9 p.m. daily and set their battery reserve to no more than 20 percent, except when preparing for or during a power outage. Customers are eligible to receive up to $20/month for participation based on their solar system's size.

Nonresidential Programs

Peak FLEXmarket

MCE's Peak FLEXmarket program is a market-driven demand flexibility program that assigns an hourly value to measured BTM impacts. Peak FLEXmarket is aimed at shifting load away from peak periods and provides customers with direct payments for measured load shedding or shifting during events, based on deviations from their individual baseline.

Peak FLEXmarket has successfully engaged new aggregators who have not participated in demand response, as well as program partners who have traditionally been confined to energy efficiency project development by presenting a value proposition for load flexibility. This program is a framework with the tools to measure and value hourly reductions in energy use and is technology agnostic.

Commercial Efficiency Market

MCE's Commercial Efficiency Market program is focused on incentivizing non-residential customers to install measures that can help reduce peak load.[19] Customers can receive a 20 percent upfront cash payment for the forecasted value of their energy efficiency projects and additional payments for metered savings of those energy efficiency projects.

5.2 Evaluation of Programs

This section evaluates the cost-effectiveness, equity, technological feasibility, and benefits to the grid and customers of implementing programs that enable automated response to MIDAS signals. As discussed below, MCE cannot currently conclude that creating a new, or modifying an existing, load-modifying program to allow automated responses to MIDAS signals would be cost effective or offer material incremental benefit, such as material incremental peak load reduction, for any customer class.

Accordingly, MCE will continue to offer voluntary participation in its existing and future load flexibility programs. MCE will continue to consider the cost-effectiveness and peak load reduction potential of programs that enable automated response to MIDAS signals. To the extent that MCE's Board does not approve a dynamic rate offering by 2027, *and* MCE is at that

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[18] *See* https://www.mcecleanenergy.org/solar-storage-credit/.
[19] *See* https://www.mcecleanenergy.org/flexmarket/.

time able to determine that modifying an existing program or creating a new program that enables automated response to MIDAS signals is cost effective and provides material incremental reductions to peak load for at least one customer class, MCE may at that time integrate a load-modifying program into MIDAS.

MCE will therefore submit to the CEC a list of load-modifying programs deemed cost-effective by October 1, 2024, but recommends the Board find that MCE is not required to include a program that allows automated response to MIDAS signals as it cannot determine such a program would be cost effective or produce material reductions to peak load for any customer class.

5.2.1 Cost Effectiveness

As outlined by section 1623.1(b)(3) of the LMS, MCE will provide a list of load-modifying programs deemed cost effective to the CEC by October 1, 2024. At present, MCE expects that the list of cost-effective programs will include the following MCE load-modifying programs:

1. Peak FLEXmarket;
2. Commercial Efficiency Market; and
3. Residential Efficiency Market.

These programs are funded by ratepayers through MCE's Energy Efficiency Portfolio as authorized by the CPUC. To receive ratepayer funding, the CPUC requires MCE to demonstrate its energy efficiency portfolio is cost effective using CPUC-approved cost-effectiveness criteria.

As it relates to the cost-effectiveness of MCE's current and future self-funded and/or grant-funded load-modifying programs (MCE Sync, Solar Storage Credit, Richmond VPP Pilot, etc.) MCE has not yet evaluated these programs for cost-effectiveness in the same manner as its ratepayer funded energy efficiency programs. Generally, MCE notes that cost-effectiveness is just one measure used to determine whether to offer a program and is not necessarily a determining factor. For example, programs that are focused on providing equity benefits may not be cost-effective utilizing traditional cost-effectiveness evaluation criteria, but still provide significant benefit to certain customer segments and society at large. MCE may robustly evaluate these programs for cost-effectiveness in the future when evaluating the effectiveness of the programs, and as it makes future determinations on program offerings.

MCE does not currently expect to utilize program offerings with automated responses to MIDAS signals; however, if MCE's Board does not adopt an hourly rate by July 1, 2027, MCE may then evaluate whether there is an opportunity to create a new program or modify an existing program to allow responses to MIDAS signals. In doing so, MCE would look at the incremental value of each option, and if modifying an existing, or creating a new, program is deemed cost-effective and found to provide material reductions to peak load may elect to do so at that time.

MCE cannot currently conclude that the modification of current or development of new programs that allow for automated responses to dynamic price signals would be cost effective for any customer class. Developing new programs or modifying existing programs would require MCE to incur costs associated with design and implementation, along with new technology costs.

While these costs could potentially be offset with capacity or energy cost savings, the magnitude of those benefits is uncertain.

In conducting future cost-effectiveness analyses, MCE would compare expected program benefits to expected costs of program design and implementation. Assuming incremental load shift that can be attributed to the program, expected benefits of a new load flexibility program that allows for automated response to MIDAS signals may include, but are not limited to, avoided energy and capacity costs, improved reliability, and environmental benefits. Expected costs may include, but are not limited to, program development costs, program administration costs, and technology and implementation costs.

5.2.2 Equity

MCE is committed to creating more equitable communities and providing equitable access to clean energy benefits throughout its service area. In choosing to modify or offer any program, MCE carefully considers equity impacts and has demonstrated its commitment to equitable program offerings since its inception. MCE aims to offer a suite of programs that provide customers with access to clean energy technology and services while lowering bills and greenhouse gas emissions. Some examples of MCE's commitment to equity include MCE's:

1. Income-qualified customer programs such as the Low-Income Families and Tenants Program, the MCE Cares Credit Program, DAC-GT program, and EV Rebate Program;
2. Commercial Equity Program;
3. Commitment to advancing supplier diversity and workforce development; and
4. MCE's Community Power Coalition.[20]

In evaluating any future load-modifying program offerings, MCE will plan to evaluate how that offering may impact customer equity. Potential evaluation criteria include, but are not limited to, equitable access to technology, direct customer benefits and bill impacts, and cost-shifting between and within rate classes. For example, most customers' ability to benefit from highly differentiated rates will be directly linked to their ability to respond to those rates. Customers that can automate portions of their load will be best equipped to respond and benefit. Therefore, equitable access to automation devices and technology will be critical in ensuring that all customers can benefit from load-modifying programs. To promote equitable access to automation technology MCE may explore providing additional incentives for low-income customers and/or those who located in disadvantaged communities or multi-family properties who may otherwise not be able to benefit from automated load shifting programs or dynamic rates.

5.2.3 Technological Feasibility

MCE is committed to offering load-modifying programs that encourage customers to shift their load away from periods of grid constraint and high greenhouse gas emissions. MCE strongly supports the LMS' goals to provide customers and their devices access to signals that may help

[20] More information on MCE's energy equity efforts can be found on its website at https://www.mcecleanenergy.org/energy-equity/#energyequity.

automate their response to marginal signals such as prices and greenhouse gas signals to provide the greatest level of benefit for both the customer and the grid. MCE has demonstrated this support through the development of its MCE Sync EV charging mobile application and the MCE Peak FLEXmarket platform, both of which are technology platforms that help customers adjust their energy consumption through greater visibility. And while MCE believes it is technically feasible to offer customers programs that allow customers to respond to MIDAS signals, currently, both of these load-modifying programs are incompatible with the MIDAS database, and MCE cannot conclude that modifying them to be compatible would be cost effective or result in material incremental load reduction:[21]

- MCE Sync - This program provides a flat monthly credit to customers for participating in events, and does not have rates associated with events, and thus would not support inclusion in MIDAS.
- PeakFLEX Market - There is currently no way for MIDAS to show customers their current real-time rate for this program, as it is based on separate prices (baseline and above-baseline) that depend on a customers' individual usage history, which is not a component of MIDAS.

As MCE's existing load-modifying programs are not currently technologically compatible with MIDAS, if MCE at a later date elects to work towards the goals of the LMS via a MIDAS enabled program offering MCE would need to determine how it could either integrate its existing programs with MIDAS or explore the creation of a new program that would be compatible with the current or future design of MIDAS. Such determinations will need to be made by the Board at a future date.

5.2.4 Benefits to the Grid and Customers

In considering whether to modify existing or offer new load-modifying programs, including those that allow automated response to MIDAS signals, MCE may consider benefits to the grid and customers.

Assuming incremental load shift or reduction that can be attributed to the program, potential grid benefits include reduced capacity costs (for example through lower Resource Adequacy costs), reduced of deferred transmission and distribution system upgrades, lower energy costs, increased reliability benefits, and environmental benefits.

Assuming incremental load shift or reduction that can be attributed to the program, potential customer benefits include pass-through energy cost savings from grid benefits as well as pass-through cost savings from potential reduced compliance costs for MCE, improved reliability, improved environmental benefits, and direct cost savings from participation in load-modifying programs.

[21] While not a load-modifying program, MCE also notes that its Disadvantaged Community Green Tariff program is also not included in MIDAS currently as it is not compatible with the current design of MIDAS. The 20 percent bill discount for the DAC-GT program is calculated from a customer's total billed charges, inclusive of non-volumetric and variable IOU charges, by reading the total charges from the previous bill. As such, MCE cannot generate a volumetric price inclusive of this discount.

All of these potential grid and customer benefits depend on the reliability and magnitude of load shift and reduction that load-modifying programs are able to achieve. MCE is at this time unable to conclude that future programs or modifications to existing programs to allow automated responses to MIDAS signals would result in material grid benefits relative to MCE's existing offerings or result in pass through savings to customers for any customer class. If MCE creates a load-modifying program that allows automated response to MIDAS signals in the future it will aim to design the program in such a way to generate material benefits to the grid and MCE customers.

6 Public Information Program

Adopted LMS Amendments Section 1623.1(b)(5) of the LMS requests MCE and other Large CCAs to conduct a public information program to inform and educate affected customers on why dynamic rates or load flexibility programs and automation are needed, how they will be used, and how these rates and programs can save customers money.

MCE appreciates the LMS' intent to ensure that any load-modifying rates or programs developed are effectively marketed to customers with the aim of encouraging enrollment and maximizing customer success and grid benefits. As a local, community-based organization, MCE values and is deeply committed to providing quality customer and community communication, education, collaboration, and customer service.

As a general matter, all MCE rates and programs can be found on MCE's website. Any future dynamic rates or load-modifying programs will also be listed and described on its webpage.[22] MCE utilizes best practices to provide consistent and accurate communications and response support with its customers and communities. This includes utilizing various communication mediums including joint rate mailers, emails, direct mail, e-newsletters, press releases, webinars, social media posts, public presentations and event attendance and sponsorship throughout MCE's member communities. In 2023 alone, MCE attended more than 250 events in our service area and presented to 69 local community organizations and city councils. MCE plans to continue communication best practices to maintain its outreach, education, and marketing of rates, programs, and pilots that support load flexibility and recognize the benefits of reducing peak load and using energy during periods of higher renewables supply. In addition, MCE has developed an in-house service center to support and effectively respond to customer inquiries and further the education and benefits of load-modifying programs.

Historically, MCE has voluntarily utilized various types of marketing campaigns to drive enrollment and successful participation in rate and program offerings including those created for load-modifying purposes. For example, to encourage customers to shift load on Time-of-Use rates, MCE conducted a public information campaign that included direct mail, website updates, digital advertising, streaming, and radio placement encouraging customers to use less energy during the 4pm - 9pm peak period targeted to customers throughout MCE's service area.[23]

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[22] MCE Residential rates can be viewed at https://www.mcecleanenergy.org/rates/. MCE Commercial rates can be viewed at https://www.mcecleanenergy.org/commercial-rates/. MCE program offerings can be found at https://www.mcecleanenergy.org/customer-programs/.

[23] *See* https://www.mcecleanenergy.org/4-9/.

MCE notes that the LMS do not include a timeline for the public information campaign. As there is no timeline expressed in the Standards and MCE has not created or recommended Board approval of any new hourly marginal cost-based rates or programs that allow automated response to MIDAS signals, MCE does not have details on what future public information programs may entail. MCE expects that if dynamic rates or new load flexibility programs are adopted MCE would utilize a public information program to drive customer adoption, understanding, and success in said rates or programs.

At a minimum, MCE would expect the public information program to highlight how individual customers may be impacted (i.e. bill impacts) and how changes to their behavior can create grid and/or environmental benefits for all customers. This type of public information program would utilize some or all the following communication mediums: direct mail, email correspondence, website updates, social media posts, webinars, television/streaming commercials, press releases or news articles, and public presentations. MCE may also work with its community partners and/or program and technology partners to develop and deliver any public information programs.

MCE expects that any public information campaign would require incremental costs that are not currently accounted for, and MCE would need to factor these public information and response program costs and their recovery into any cost-effectiveness analysis and recommendation to its Board.

7 Appendix

Appendix A – MCE MIDAS Rate Identification Numbers

The below table displays the RINs associated with each of MCE's residential and non-residential rates and rate permutations that have been uploaded to MIDAS.

RIN	Rate Schedule	Energy Supply Product
USCA-XXMC-PBZD-0000	ETOUB	Deep Green
USCA-XXMC-PCZD-0000	ETOUC	Deep Green
USCA-XXMC-PDZD-0000	ETOUD	Deep Green
USCA-XXMC-OZZD-0000	ELEC	Deep Green
USCA-XXMC-QAZD-0000	EVA	Deep Green
USCA-XXMC-QUZD-0000	EV2	Deep Green
USCA-XXMC-AXZD-0000	A1X	Deep Green
USCA-XXMC-EZZD-0000	B1	Deep Green
USCA-XXMC-ETZD-0000	B1ST	Deep Green
USCA-XXMC-CZZD-0000	A6	Deep Green
USCA-XXMC-IZZD-0000	B6	Deep Green
USCA-XXMC-BXCD-0000	A10SX	Deep Green
USCA-XXMC-FZCD-0000	B10S	Deep Green
USCA-XXMC-BXBD-0000	A10PX	Deep Green
USCA-XXMC-FZBD-0000	B10P	Deep Green
USCA-XXMC-BXDD-0000	A10TX	Deep Green
USCA-XXMC-FZDD-0000	B10T	Deep Green
USCA-XXMC-LZCD-0000	E19S	Deep Green
USCA-XXMC-GZCD-0000	B19S	Deep Green
USCA-XXMC-LZBD-0000	E19P	Deep Green
USCA-XXMC-GZBD-0000	B19P	Deep Green
USCA-XXMC-LZDD-0000	E19T	Deep Green
USCA-XXMC-GZDD-0000	B19T	Deep Green
USCA-XXMC-LRCD-0000	E19SR	Deep Green
USCA-XXMC-GRCD-0000	B19SR	Deep Green
USCA-XXMC-LRBD-0000	E19PR	Deep Green
USCA-XXMC-GRBD-0000	B19PR	Deep Green
USCA-XXMC-LRDD-0000	E19TR	Deep Green
USCA-XXMC-GRDD-0000	B19TR	Deep Green
USCA-XXMC-MZCD-0000	E20S	Deep Green
USCA-XXMC-HZCD-0000	B20S	Deep Green
USCA-XXMC-MZBD-0000	E20P	Deep Green
USCA-XXMC-HZBD-0000	B20P	Deep Green

RIN	Rate Schedule	Energy Supply Product
USCA-XXMC-MZDD-0000	E20T	Deep Green
USCA-XXMC-HZDD-0000	B20T	Deep Green
USCA-XXMC-MRCD-0000	E20SR	Deep Green
USCA-XXMC-HRCD-0000	B20SR	Deep Green
USCA-XXMC-MRBD-0000	E20PR	Deep Green
USCA-XXMC-HRBD-0000	B20PR	Deep Green
USCA-XXMC-MRDD-0000	E20TR	Deep Green
USCA-XXMC-HRDD-0000	B20TR	Deep Green
USCA-XXMC-DAED-0000	AGA1	Deep Green
USCA-XXMC-DAFD-0000	AGA2	Deep Green
USCA-XXMC-DBZD-0000	AGB	Deep Green
USCA-XXMC-DCZD-0000	AGC	Deep Green
USCA-XXMC-DGED-0000	AGFA1	Deep Green
USCA-XXMC-DGFD-0000	AGFA2	Deep Green
USCA-XXMC-DGGD-0000	AGFA3	Deep Green
USCA-XXMC-DHED-0000	AGFB1	Deep Green
USCA-XXMC-DHFD-0000	AGFB2	Deep Green
USCA-XXMC-DHGD-0000	AGFB3	Deep Green
USCA-XXMC-DIED-0000	AGFC1	Deep Green
USCA-XXMC-DIFD-0000	AGFC2	Deep Green
USCA-XXMC-DIGD-0000	AGFC3	Deep Green
USCA-XXMC-DJZD-0000	AG4A	Deep Green
USCA-XXMC-DKZD-0000	AG4B	Deep Green
USCA-XXMC-DLZD-0000	AG4C	Deep Green
USCA-XXMC-DMZD-0000	AG5A	Deep Green
USCA-XXMC-DNZD-0000	AG5B	Deep Green
USCA-XXMC-DOZD-0000	AG5C	Deep Green
USCA-XXMC-TZCD-0000	STOUS	Deep Green
USCA-XXMC-TZBD-0000	STOUP	Deep Green
USCA-XXMC-TZDD-0000	STOUT	Deep Green
USCA-XXMC-SZCD-0000	SBS	Deep Green
USCA-XXMC-SZBD-0000	SBP	Deep Green
USCA-XXMC-SZDD-0000	SBT	Deep Green
USCA-XXMC-JZED-0000	BEV1	Deep Green
USCA-XXMC-JUCD-0000	BEV2S	Deep Green
USCA-XXMC-JUBD-0000	BEV2P	Deep Green
USCA-XXMC-NZZD-0000	E6	Deep Green
USCA-XXMC-PBZL-0000	ETOUB	Light Green
USCA-XXMC-PCZL-0000	ETOUC	Light Green
USCA-XXMC-PDZL-0000	ETOUD	Light Green
USCA-XXMC-OZZL-0000	ELEC	Light Green

RIN	Rate Schedule	Energy Supply Product
USCA-XXMC-QAZL-0000	EVA	Light Green
USCA-XXMC-QUZL-0000	EV2	Light Green
USCA-XXMC-AXZL-0000	A1X	Light Green
USCA-XXMC-EZZL-0000	B1	Light Green
USCA-XXMC-ETZL-0000	B1ST	Light Green
USCA-XXMC-CZZL-0000	A6	Light Green
USCA-XXMC-IZZL-0000	B6	Light Green
USCA-XXMC-BXCL-0000	A10SX	Light Green
USCA-XXMC-FZCL-0000	B10S	Light Green
USCA-XXMC-BXBL-0000	A10PX	Light Green
USCA-XXMC-FZBL-0000	B10P	Light Green
USCA-XXMC-BXDL-0000	A10TX	Light Green
USCA-XXMC-FZDL-0000	B10T	Light Green
USCA-XXMC-LZCL-0000	E19S	Light Green
USCA-XXMC-GZCL-0000	B19S	Light Green
USCA-XXMC-LZBL-0000	E19P	Light Green
USCA-XXMC-GZBL-0000	B19P	Light Green
USCA-XXMC-LZDL-0000	E19T	Light Green
USCA-XXMC-GZDL-0000	B19T	Light Green
USCA-XXMC-LRCL-0000	E19SR	Light Green
USCA-XXMC-GRCL-0000	B19SR	Light Green
USCA-XXMC-LRBL-0000	E19PR	Light Green
USCA-XXMC-GRBL-0000	B19PR	Light Green
USCA-XXMC-LRDL-0000	E19TR	Light Green
USCA-XXMC-GRDL-0000	B19TR	Light Green
USCA-XXMC-MZCL-0000	E20S	Light Green
USCA-XXMC-HZCL-0000	B20S	Light Green
USCA-XXMC-MZBL-0000	E20P	Light Green
USCA-XXMC-HZBL-0000	B20P	Light Green
USCA-XXMC-MZDL-0000	E20T	Light Green
USCA-XXMC-HZDL-0000	B20T	Light Green
USCA-XXMC-MRCL-0000	E20SR	Light Green
USCA-XXMC-HRCL-0000	B20SR	Light Green
USCA-XXMC-MRBL-0000	E20PR	Light Green
USCA-XXMC-HRBL-0000	B20PR	Light Green
USCA-XXMC-MRDL-0000	E20TR	Light Green
USCA-XXMC-HRDL-0000	B20TR	Light Green
USCA-XXMC-DAEL-0000	AGA1	Light Green
USCA-XXMC-DAFL-0000	AGA2	Light Green
USCA-XXMC-DBZL-0000	AGB	Light Green
USCA-XXMC-DCZL-0000	AGC	Light Green

RIN	Rate Schedule	Energy Supply Product
USCA-XXMC-DGEL-0000	AGFA1	Light Green
USCA-XXMC-DGFL-0000	AGFA2	Light Green
USCA-XXMC-DGGL-0000	AGFA3	Light Green
USCA-XXMC-DHEL-0000	AGFB1	Light Green
USCA-XXMC-DHFL-0000	AGFB2	Light Green
USCA-XXMC-DHGL-0000	AGFB3	Light Green
USCA-XXMC-DIEL-0000	AGFC1	Light Green
USCA-XXMC-DIFL-0000	AGFC2	Light Green
USCA-XXMC-DIGL-0000	AGFC3	Light Green
USCA-XXMC-DJZL-0000	AG4A	Light Green
USCA-XXMC-DKZL-0000	AG4B	Light Green
USCA-XXMC-DLZL-0000	AG4C	Light Green
USCA-XXMC-DMZL-0000	AG5A	Light Green
USCA-XXMC-DNZL-0000	AG5B	Light Green
USCA-XXMC-DOZL-0000	AG5C	Light Green
USCA-XXMC-TZCL-0000	STOUS	Light Green
USCA-XXMC-TZBL-0000	STOUP	Light Green
USCA-XXMC-TZDL-0000	STOUT	Light Green
USCA-XXMC-SZCL-0000	SBS	Light Green
USCA-XXMC-SZBL-0000	SBP	Light Green
USCA-XXMC-SZDL-0000	SBT	Light Green
USCA-XXMC-JZEL-0000	BEV1	Light Green
USCA-XXMC-JUCL-0000	BEV2S	Light Green
USCA-XXMC-JUBL-0000	BEV2P	Light Green
USCA-XXMC-NZZL-0000	E6	Light Green

MARIN CLEAN ENERGY

LOAD MANAGEMENT STANDARDS PLAN

~~March 29~~Approved by MCE Board May 16, 2024

1 Table of Contents

2 Introduction

2.1 About MCE

Marin Clean Energy ("MCE") is California's first Community Choice Aggregation ("CCA") Program, a not-for-profit Joint Powers Authority ("JPA") that began serving customers in 2010. MCE's mission is to confront the climate crisis by eliminating fossil fuel greenhouse gas ("GHG") emissions, producing renewable energy, and creating equitable community benefits. MCE's vision is to lead California to an equitable, clean, affordable, and reliable energy economy by serving as a model for community-based renewable energy, energy efficiency, and cutting-edge clean-tech products and programs.

As a load-serving entity ("LSE") MCE provides electricity generation service to approximately 580,000 customer accounts. These accounts represent more than one million residents and businesses across four Bay Area counties.[1] MCE procures for annual retail sales of approximately 5,729 GWh and a peak load of more than 1,240 MW.

MCE provides service to approximately 87 percent of eligible customers within its service area, which is depicted below in Figure 1. MCE is also the default generation provider for any new or relocated customers therein.

Figure 1: MCE Service Area Map

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[1] MCE serves communities across Contra Costa, Marin, Napa, and Solano counties. Those communities currently receiving service include: Unincorporated Contra Costa, Marin, Napa, and Solano counties and the Cities and Towns of Concord, Danville, El Cerrito, Lafayette, Martinez, Moraga, Oakley, Pinole, Pittsburg, Pleasant Hill, Richmond, San Pablo, San Ramon, Walnut Creek, Belvedere, Corte Madera, Fairfax, Larkspur, Mill Valley, Novato, Ross, San Anselmo, San Rafael, Sausalito, Tiburon, American Canyon, Calistoga, Napa, St. Helena, Yountville, Benicia, Vallejo, and Fairfield. MCE expects service to expand to include the City of Hercules in April of 2025.

As a JPA and local government agency, MCE is governed by a 34-member Board of Directors ("Board" or "Governing Board") composed of elected representatives from MCE's member communities. MCE's Board sets policy for the agency and oversees operations, including rates and procurement planning. Through these representatives, MCE is controlled by and accountable to the communities MCE serves.

MCE was formed to empower its member communities to choose the generation resources that reflect their specific values and needs. As a mission-driven local government agency, MCE works toward the following:

- Reducing GHG emissions and accelerating the supply of clean energy being delivered to and used on the grid;
- Developing community programs and local energy projects to expand access to competitively priced renewable energy and energy efficiency programs for all customers;
- Creating economic and workforce benefits associated with renewable energy and energy conservation programs; and
- Leveraging energy and conservation spending to promote more equity throughout MCE's communities and California.

2.2 Load Management Standards

In Docket Number 21-OIR-03 the California Energy Commission ("CEC") adopted Revised Load Management Standards ("LMS" or "Standards"). The amendments to the LMS, which became effective on April 1, 2023, are intended to form the foundation for a statewide system of time and locational dependent signals that can be used by automation-enabled devices to encourage load flexibility on the electric grid. Simply, the Standards are intended to encourage automated load shifting of electricity to off-peak hours.

To accomplish the goals of the LMS, the regulations request California's large CCAs,[2] investor-owned utilities ("IOUs"), and large publicly owned utilities ("POUs") to offer customers access to rate-structures and/or programs that allow automated responses to prices or other grid signals to manage and optimize their energy use.

Specifically, the LMS request large CCAs to (1) develop and propose marginal cost-based rates that vary at least hourly[3] or, (2) if the Board finds that implementing marginal cost-based hourly rates would not materially reduce peak load, be technologically feasible, and/or be cost-effective, offer a load flexibility program that allows at least one option for automating response to the CEC's Market Informed Demand Automation Server ("MIDAS") signals for customer classes where MCE's Board determines such a program would materially reduce peak load and be cost-effective. For the purposes of this plan, MCE will refer to marginal cost-based rates that vary at least hourly as defined in the LMS as "hourly" or "dynamic" rates.

[2] The LMS define Large CCAs as any CCA that provides in excess 700 GWh of electricity to customers in any calendar year.

[3]Section 1623.1(b)(1) of the LMS define a marginal cost-based rate 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, including the locational marginal cost of associated greenhouse gas emissions, on a time interval of no more than one hour.

2.2.1 MCE LMS Plan and Board Authority

Section 1623.1(a) requests each large CCA submit a plan outlining how it plans to meet the objectives of the LMS to its Board by April 1, 2024.

As a large CCA that shares the goals and objectives of the LMS to better align demand of electricity with periods of high renewable energy supply and encouraging automated load shifting away from peak periods, MCE submits this plan to the Board for approval. [4] The purpose of this plan is to identify the steps and activities MCE plans to voluntarily undertake which align with the goals of the LMS.

MCE notes that nothing in this plan overrides or supersedes MCE's Board's sole authority as the governing and rate-making body of MCE.[5] Nothing in this plan implies any jurisdictional authority of the CEC over MCE's rates and rate programs. MCE is currently voluntarily taking reasonable steps that meet the standards within the LMS regulations.

Additionally, as outlined in the LMS, MCE's Board may approve a plan, or material revisions to a previously approved plan, that delays implementation of or modifies the goals of LMS Subsections 1623.1(b)-(c), if the Board determines that despite good faith efforts implantation:

- Would result in extreme hardship to MCE;
- Would result in reduced system reliability (e.g., equity or safety) or efficiency;
- Would not be technologically feasible or cost effective; or
- Must be modified to provide a more technologically feasible, equitable, safe, or cost-effective way to achieve the LMS or plan's goals.

Accordingly, MCE submits this plan to the Board for adoption and approval to implement as outlined herein. Table 1 below provides a list of each regulatory standard or goal as outlined in the LMS and MCE's plan to meet that standard or goal at the time of this writing. As described, MCE plans to continue to offer its portfolio of current and planned load flexibility programs and time dependent rates aimed at encouraging customers to use energy in off-peak hours, and will continue to explore how it may offer new cost-effective dynamic rates, pilots, and load flexibility programs that materially reduce peak load, encourage load control through automation, and provide reliability and environmental benefits for MCE customers and the California electric grid.

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[4] Consistent with Section 1623.1(a) of the LMS, MCE submitted this plan to its Board on March 29, 2024, and will submit this plan to the CEC within 30 days of Board approval.

[5] Public Utilities Code Section 366.2(c)(3) provides that CCAs retain jurisdiction for setting rates for the electricity they purchase on behalf of their communities.

Table 1: MCE LMS Roadmap

Load Management Standards Section	Standard Description	Target Date	MCE Adopted Plan to Meet Standard
§1623.1(c)	Upload existing time-dependent rates to MIDAS database.	July 1, 2023	Status: Achieved MCE plans to maintain future rates in MIDAS to the extent it is cost effective and technologically feasible. MCE cannot confirm that uploading future dynamic rates or programs to MIDAS will be cost effective or technologically feasible.
§1623.1(a)(1)	Develop and submit a plan for adoption to MCE's Board addressing how MCE plans to meet objectives of the LMS. The plan is to be considered for adoption by MCE's Board within 60 days of submission at a duly noticed public meeting.	April 1, 2024	Status: Achieved
§1623.1(a)(3)(A)	Within 30 days of adoption of the plan, submit the plan to the CEC's Executive Director.	30 Days After Board Adoption	Status: MCE will submit this plan to the CEC within 30 days of Board adoption.
§1623(c)	Within one year of LMS effective date, provide customers access to their Rate Identification Numbers on billing statements and in online accounts using both text and quick response code format.	April 1, 2024	Status: In Progress, Expected to Achieve
§1623(c)	In conjunction with the other named LSEs, develop and submit to the CEC a plan for a single statewide standard tool for authorized rate data access by third parties and the terms and conditions for using the tool. Upon CEC approval, maintain and implement the tool.	October 1, 2024	Status: In Progress MCE is engaged in and monitoring the development process for the single statewide tool.

Load Management Standards Section	Standard Description	Target Date	MCE Adopted Plan to Meet Standard
§1623.1(b)(3)	Submit to the CEC a list of load flexibility programs deemed cost effective by MCE. The portfolio of programs should provide at least one option to automate response to MIDAS signals for each customer class where MCE's Board has determined such a program would materially reduce peak load.	October 1, 2024	Status: In Progress MCE cannot determine that such a program will materially reduce peak load for any customer class. MCE will submit a list of programs deemed cost effective to the CEC but does not expect to include an option to automate response to MIDAS signal at this time.
§1623.1(a)(3)(C)	Submit annual reports to the CEC demonstrating implementation of the plan, as approved by the Board.	Annually	Status: In Progress MCE will submit annual reports beginning one year after the adoption of this plan.
§1623.1(b)(2)	Submit at least one marginal cost-based rate to MCE's Board for approval for any customer class(es) where such a rate will materially reduce peak load. An Information copy of the tariff applications will be provided to the CEC.	July 1, 2025	Status: In Progress At this time MCE cannot determine that such a rate or will provide material, incremental reductions to peak load or be cost effective for any customer class. However, MCE is interested in collecting the data necessary to make such determinations and will continue to explore options to offer dynamic rate pilots in its service territory. MCE therefore recommends the Board modify this standard and determine that MCE may, but is not required to, propose such a rate or program by the target date. MCE will continue to evaluate and address in its next plan iteration and any annual reports.
§1623.1(b)(4)	Offer each customer voluntary participation in either a marginal cost-based rate, if approved by the Board, or a cost-effective load flexibility program.	July 1, 2027	Status: To be determined by future Board direction. MCE notes that this target date is after the next review of MCE's LMS is expected to be completed. As such, MCE will likely provide an update in its next LMS plan as appropriate.

Load Management Standards Section	Standard Description	Target Date	MCE Adopted Plan to Meet Standard
§1623.1(b)(5)	Conduct a public information program to inform and educate affected customers on why marginal cost-based rates or load flexibility programs and automation are needed, how they will be used, and how these rates and programs can save customers money.	No Target Date Specified	Status: To be determined by future Board direction and future adoption of dynamic rates or load-modifying programs.
§1623.1(a)(1)(C)	Review the plan at least once every three years after the plan is adopted and submit a plan update to the Board if there is a material change.	Once Every Three Years	Status: MCE will review its LMS plan at least once every three years following the date of adoption.

3 Access to Price Signals

3.1 Time-Dependent Rate Submission to MIDAS

Adopted LMS Amendments Section 1623.1(c) requests each Large CCA upload existing time dependent rates to the MIDAS database by July 1, 2023. On June 1, 2023, the CEC issued Order No. 23-0531-109 approving an extension for CCAs to upload time-dependent generation rates by August 1, 2023, and any remaining time-depending rates with rate modifiers by October 1, 2023. Large CCAs are also asked to upload any new time-dependent rates or changes to existing rates, prior to the effective date of that rate.

3.1.1 Existing Rates Upload

MCE successfully uploaded all of its 70 active Light Green service rates by the CEC's target date of August 1, 2023, and uploaded its Deep Green service rates by the target date of October 1, 2023, to include time-dependent rates with additional modifiers. A complete list of rates uploaded to MIDAS and their associated Rate Identification Numbers ("RIN") is included in Appendix A.

The period covered by the initial upload spanned between three and six months, due to data limitations of the MIDAS system. As such, MCE has made subsequent uploads to keep rates current in MIDAS:

1. In October 2023, MCE uploaded additional intervals to ensure all rates were up-to-date through December 31, 2023.

2. In November 2023, MCE uploaded additional intervals for all rates through May 1, 2024.[6]

3.1.2 Future Rates Upload

To the extent that uploading future rates is feasible and cost effective, MCE plans to maintain its generation rates in MIDAS so that customers and their devices may access them for device automation. However, MCE notes that if hourly rates are approved by MCE's Board, daily uploads of such rates to MIDAS will present significant challenges. Given the current structure of MIDAS and the lack of funding for LSEs to develop systems, processes, and improvements to MIDAS, MCE cannot at this time find that it is cost effective or feasible to maintain current and accurate rates for any future hourly rate offerings in MIDAS.

Nonetheless, MCE is engaged in and monitoring the Demand Flexibility Proceeding at the California Public Utilities Commission ("CPUC") and is committed to working with the CEC, CPUC, and other stakeholders to help customers automate behavioral changes in electric usage and looks forward to further discussion on how MIDAS may be updated and/or will interact with future rate platforms or repositories yet to be developed such as a CPUC approved Price Machine.

MCE recommends that any future rate repositories be equipped to provide composite rates if the goal is to provide customers with a composite or total real-time rate signal. As a CCA, MCE's Board has sole authority over its customers' generation rate component but has no authority to determine the distribution or transmission rate components of its customers' rates. Any distribution and transmission rate components charged to MCE customers are charged by Pacific Gas & Electric Company ("PG&E"). As such, MCE only plans to upload generation rate components to MIDAS and cannot take responsibility for, be required to calculate, or be required to upload marginal cost rates for rate components and myriad PG&E programs that it has no control over.

3.2 Plan to Provide Rate Identification Number(s) on Customer Billing Statements and Online Account Using Both Text and QR Code

Adopted LMS Amendments Section 1623(c)(4) requests each Large CCA to provide customers with access to their RIN on customer billing statements and online accounts using both text and quick response ("QR") or similar machine-readable digital code by April 1, 2024.

MCE customers receive their consolidated billing statements from PG&E. MCE provides itemized charges to PG&E through Electronic Data Interchange ("EDI") transactions. Therefore, MCE is reliant on PG&E to develop its EDI system to accept MCE RINs and display them on customer bills.

[6] As of this writing, six of MCE's Light Green rates are not current in the MIDAS system. These rates serve a small number of large Commercial & Industrial and EV customers with legacy 12p-6p peak periods. Upload attempts are rejected with the message, "An error has occurred." MCE reached first reached out to CEC staff on November 30, 2023, and has had numerous, ongoing communications with CEC staff on this matter. The issue appears to reside with MIDAS, and not with MCE. CEC Staff has indicated they are aware of the issue, that it is not isolated to MCE and the CEC is working to resolve the issue. MCE will continue to engage and collaborate with the CEC in good faith to fix this issue.

CCAs have been working with PG&E to utilize PG&E's billing transactions to include a CCA specific RIN on customers' bills. MCE will supply MCE's RIN mapping table to PG&E who will then include it within the code and display customers' RINs on the generation portion of their bills. This interpretation has also been corroborated by PG&E in recent CPUC Advice Letters seeking approval to modify customers' bill presentations to include RINs and QR codes.

On January 16, 2024, PG&E filed Advice Letter 7136-E at the CPUC outlining the process it is undertaking to provide RINs on customer bills. As outlined by PG&E in its second supplemental Advice Letter 7136-E-B filed on March 1, 2024, customers on time-dependent rates will have their bills updated to include a QR code and the customer's RIN in the top right-hand corner of their bill, which can then be scanned to program a customer's device(s). PG&E notes that RINs will be presented the same way on both bundled and unbundled (CCA and Direct Access) customers' bills.

3.3 Plans and Current Participation in the Development of Single Statewide RIN Access Tool *– Amended July 2025*

Adopted LMS Amendments Section 1623(c)(1)-(3) requests all LSEs named in the Standards to work together to develop a plan for a single statewide standard tool for authorized rate data access by third parties, along with a single set of terms and conditions for third parties using the tool by October 1, 2024. The tool is to provide the customers' RINs, provide eligible RINs, enable switching to an available rate by an authorized third party, incorporate applicable cybersecurity measures, minimize enrollment barriers, and be accessible in digital, machine-readable format.

MCE is monitoring and engaging in the process with the other regulated LSEs to develop a Single Statewide RIN Access Tool ~~and~~pursuant to Adopted LMS Amendments Section 1623(c). A proposed plan for the tool was submitted to the CEC for review on October 1, 2024. MCE will continue to collaborate with other parties ~~on~~and the CEC towards the implementation and maintenance of the tool in a timely manner subject to the tool's ~~development ahead of the October 1, 2024, target date. At the time of this writing~~approval by the CEC. MCE is unable to specifically identify the full scope and budget of integration of work; commit resources; or review, identify, and plan internal infrastructure needs until the Single Statewide Standard RIN Access Tool's scope has been designed and approved by the CEC.

4 MCE Rates and Dynamic Rate Considerations

Adopted LMS Amendments Section 1623.1(a)(1) requests each large CCA to develop a plan that evaluates the cost-effectiveness, equity, technological feasibility, benefits to the grid, and benefits to customers of dynamic rates for each customer class. After evaluating dynamic rates, the CCA may instead propose and evaluate specified programs and/or delay or modify its implementation of the LMS.

Adopted LMS Amendments Section 1623.1(b)(2) requests MCE apply to its rate-approving body for approval of at least one dynamic rate by July 1, 2025. The LMS state MCE is to apply for approval only of a dynamic rate only for those customer classes for which the Board determines such a rate will materially reduce peak load.

Adopted LMS Amendments Section 1623.1(b)(4) requests each CCA to offer to each of its electricity customers voluntary participation in either a dynamic rate developed according to Section 1623.1(b)(2), if such rate is approved by the Board, or a cost-effective load flexibility program that allows automated response to MIDAS signals for each customer class the Board determines such a program would materially reduce peak load July 1, 2027.

This section provides an overview of MCE's current time-dependent rates and its plan to evaluate and develop dynamic rates as stated in the LMS.

4.1 Overview of MCE's Current Time-Dependent Rate Offerings

MCE currently offers several options for time-dependent or Time-Of-Use ("TOU") pricing, consistent with the options available to the broader PG&E service area. Approximately 66 percent of MCE households are on time-dependent rates. Current residential rate options are displayed in the table below.

Table 2: Current MCE Residential Rate Offerings[7]

MCE Residential Rate	Description of Rate Periods
E-1	Flat Rate Pricing, not time dependent
E-TOU-C - Default Time-of-Use	Utilizes 4pm-9pm peak rates every day
E-TOU-D - Time-of-Use	Utilizes 5pm-9pm peak rates on non-holiday weekdays only
ELEC - Time-of-Use for Qualified Electric Technologies	Utilizes lower rates from 12am-3pm
EV2 - Time-of-Use for Electric Vehicles	Utilizes lower rates from 12am-3pm

Additionally, MCE continues to provide limited service to legacy residential rate schedules that are no longer available to new customers:

- E-TOU-B - Time-of-Use: Utilizes 4pm-9pm peak rates on non-holiday weekdays only; and
- EV - Time-of-Use for Solar Customers with Electric Vehicles: Utilizes lower rates from 11pm-2pm.

MCE also offers a wide range of options for time-dependent pricing for non-residential customers as depicted in Table 3 below. Except in rare circumstances like street lighting, non-residential service is entirely billed according to time-dependent pricing. All of MCE's

[7] A complete list of MCE Residential rates can be found at https://www.mcecleanenergy.org/rates/.

non-residential rates have 4pm-9pm daily peak and seasonal rates, except where noted otherwise.

Table 3: Current MCE Non-Residential Rate Offerings[8]

MCE Non-Residential Rates	Description of Rate Periods
B-1 - Small General Service	Utilizes six TOU periods (three in the Summer and three in the Winter)
B-1ST - Small General Service Plus Storage	Utilizes seven TOU periods (three in the Summer and four in the Winter)
B-6 - Small General Service	Utilizes five TOU periods (two in the Summer and three in the Winter) and stronger pricing signals relative to rate schedule B-1
B-10 - Medium General Service	Utilizes six TOU periods (three in the Summer and three in the Winter) and three voltage levels with discrete rates
B-19 - Medium General Service	Utilizes six TOU periods (three in the Summer and three in the Winter), TOU and seasonal based demand charges, and three voltage levels with discrete rates
B-19 Option R - Medium General Service for Solar	Utilizes six TOU periods (three in the Summer and three in the Winter), no demand charges, and three voltage levels with discrete rates
B-20 Option R - Large General Service for Solar	Utilizes six TOU periods (three in the Summer and three in the Winter), no demand charges, and three voltage levels with discrete rates
BEV - Commercial EV Charging	Utilizes three TOU periods, no seasonality, and three voltage levels with discrete rates
AG-A - Small Agriculture	Utilizes four TOU periods (two in the Summer and two in the Winter), and uses a 5pm-8pm peak pricing period

[8] A complete list of MCE Non-Residential rates can be found at https://www.mcecleanenergy.org/commercial-rates/.

MCE Non-Residential Rates	Description of Rate Periods
AG-B - Medium Agriculture	Utilizes four TOU periods (two in the Summer and two in the Winter), 5pm-8pm peak pricing period
AG-C - Large Agriculture	Utilizes four TOU periods (two in the Summer and two in the Winter), 5p-8p peak, summer peak demand
AG-F - Flexible TOU Agriculture	Utilizes AG-A/AG-B/AG-C variations as above, with two designated 24-hour off-peak days
SB - Standby Service	Utilizes six TOU periods (three in the Summer and three in the Winter), a reservation charge per kW, and three voltage levels with discrete rates
SL-1 - Street, Highway, and Outdoor Lighting	This rate is not time dependent
TC-1 - Traffic Control Service	This rate is not time dependent

MCE also continues to offer limited service to legacy non-residential rate schedules without a 4pm-9pm peak. Eligibility is determined by PG&E according to tariffs approved by the CPUC. These rates have a 12pm-6pm peak and seasonal rates, except where otherwise noted, and have weak pricing signals and are of limited significance to MCE's portfolio. Only 6.5 percent of MCE customers – almost entirely small commercial accounts – are served by these rates.

Table 4: MCE Legacy Rates

MCE Legacy Rates	Description of Rate Periods
A-1 - Small General Service	This is a non-TOU rate
A-1X - Small General Service	Utilizes five TOU periods (three in the Summer and two in the Winter)
A-6 - Small General Service	Utilizes five TOU periods (three in the Summer and two in the Winter)
A-10 - Medium General Service	This is a non-TOU rate but includes three voltage levels with discrete rates

MCE Legacy Rates	Description of Rate Periods
A-10X - Medium General Service	Utilizes five TOU periods (three in the Summer and two in the Winter) and three voltage levels with discrete rates
E-19 - Medium General Service	Utilizes five TOU periods (three in the Summer and two in the Winter), demand charges, and three voltage levels with discrete rates
E-20 - Large General Service	Utilizes five TOU periods (three in the Summer and two in the Winter), and three voltage levels with discrete rates
E-20 Option R - Large General Service for Solar Customers	Utilizes five TOU periods (three in the Summer and two in the Winter), and three voltage levels with discrete rates
AG-1 - Small Agricultural Service	This is a non-TOU rate
AG-4-A - Time-of-Use Agricultural Service	Time-of-Use Agricultural Service: Includes four TOU periods (two in the Summer and two in the Winter) and a connected load charge
AG-4-B - Time-of-Use Agricultural Service	Utilizes four TOU periods (two in the Summer and two in the Winter) and a maximum demand charge
AG-4-C - Time-of-Use Agricultural Service	Utilizes five TOU periods (three in the Summer and two in the Winter) and a peak demand charge
AG-5-A - Time-of-Use Agricultural Service	Utilizes four TOU periods (two in the Summer and two in the Winter) and a connected load charge
AG-5-B - Time-of-Use Agricultural Service	Utilizes four TOU periods (two in the Summer and two in the Winter) and a maximum demand charge
AG-5-C - Time-of-Use Agricultural Service	Utilizes five TOU periods (three in the Summer and two in the Winter) and a peak demand charge
AG-R - Time-of-Use Agricultural Service with Off Peak Days	Utilizes four TOU periods (two in the Summer and two in the Winter), two day-

MCE Legacy Rates	Description of Rate Periods
	of-week options, two service levels, and connected load or demand charges
AG-R - Time-of-Use Agricultural Service with Variable Peak	Utilizes four TOU periods (three in the Summer and two in the Winter), three peak hour options, two service levels, and connected load or demand charges
S - Standby Service	Utilizes five TOU periods (three in the Summer and two in the Winter), reservation charge per kW, and three voltage levels with discrete rates

MCE also offers two energy supply programs that are charged or credited to the customer's energy bill but separate from each customer's electric rate schedule:

- Deep Green Service: This program allows customers to choose 100 percent renewable energy content and includes a $0.01/kWh flat adder to all rates.
- Disadvantaged Communities Green Tariff ("DAC-GT"): This program allows eligible customers in disadvantaged communities to choose 100 percent renewable energy content and receive a 20 percent total bill discount.

4.2 Dynamic Rates Evaluation *– Amended July 2025*

MCE strongly appreciates and supports the LMS' goals to help encourage customers to shift energy consumption away from peak periods to minimize costs, improve reliability, and better align renewable energy supply and demand. MCE also agrees that two tools that can be utilized to encourage such a shift are flexible rate designs and automation technology.

Consistent with the adopted LMS, in this section MCE outlines its plan to evaluate future dynamic marginal cost-based rate offerings for its customers and provides an initial evaluation of the cost-effectiveness, equity, technological feasibility, and benefits of dynamic rates.

As a CCA, MCE's Board has sole authority over its customers' generation rate component and no other entity, including the CEC or CPUC, has the authority to set generation rates for MCE customers. Similarly, this means that MCE does not have authority to determine the distribution or transmission rate components of its customers. ~~-~~Any distribution and transmission rate components charged to MCE customers are determined and charged by PG&E, as approved by the CPUC and/or Federal Energy Regulatory Commission. As such, any dynamic or hourly rates adopted by MCE's Board will be generation-only. MCE and its Board cannot take responsibility for, or be required to calculate, rates for components that it has no control over such as distribution and transmission rate components.

~~While MCE has not yet offered any dynamic rates or dynamic rate pilots,~~ MCE understands that there may be value in ~~such~~dynamic rates or dynamic rate pilots, and is currently ~~evaluating~~

~~whether it may offer one of~~offering all the dynamic rate pilots approved by the CPUC for PG&E's service area[9] ~~or whether it may propose~~as well as offering its own, distinct dynamic EV rate pilot~~(s)~~ to its customers, ~~which would~~MCE Sync Dynamic Rewards.[10] These pilots should allow MCE to collect ~~the~~ data ~~necessary~~ to evaluate the cost-effectiveness, equity, feasibility, and customer and grid benefits of such rates to inform MCE's future rate designs and offerings. Generally, MCE notes that it has a preference to create and offer MCE specific rates, pilots, and programs that can be uniquely tailored and administered by MCE to meet the needs of its customers, which may be distinct from other regions of PG&E's service area and rely on MCE's significantly clean and GHG-free portfolio in the California Independent System Operator markets.

In evaluating whether to offer future additional dynamic rates and/or pilots, MCE plans to evaluate portfolio-based cost-effectiveness, technical feasibility, equity, and benefits to MCE and its customers and the environment. MCE will consider what pricing options, if any, offer cost-effective and material, incremental, benefits over current rate and load flexibility offerings. ~~Potential~~Offering dynamic rate pilots should provide necessary and useful data to evaluate and determine the appropriateness (and potential design) of future dynamic rate offerings in MCE's service area.

~~As discussed below MCE does not at this time~~In the version of this plan approved by the Board on May 16, 2024, MCE found that it did not have sufficient evidence to conclude that developing and implementing dynamic rates in MCE's service area on the timeline outlined in the LMS would be cost effective or provide material incremental reductions to peak load beyond those of its current rate and programs portfolio for any customer class. ~~As such MCE cannot currently~~The Board-approved plan found it necessary to modify Section 1623.1(b)(2)'s request for MCE to apply for approval of a dynamic rate by July 1, 2025. The Board-approved plan concluded that the timeline must be modified to ensure cost-effective implementation and that MCE Staff may, but was not required to, propose such a rate to the Board by the target date of July 1, 2025. At that time, MCE could not commit to creating such a rate for Board approval by July 1, 2025. However, MCE is interested in collecting the data necessary to make such determinations and is ~~exploring options to offer~~now offering dynamic rate pilots in its service territory. MCE ~~therefore recommends~~began offering the ~~Board find it necessary to modify Section 1623.1(b)(2)'s request for~~ MCE ~~to apply for approval of a~~ Sync Dynamic Rewards pilot in September 2024, and on April 4, 2025, MCE's Board approved MCE's participation in the dynamic rate ~~by July 1, 2025. MCE recommends the Board conclude that~~ pilots offered in PG&E's service area: Expanded Pilot 1, Expanded Pilot 2, and the VGI-Commercial Pilot, and therefore has met the original timeline ~~must be modified to ensure cost-effective implementation and determine that MCE Staff may, but is not required to, propose such a rate to the Board by the target date of July 1,~~

[9] ~~For example,~~ California Public Utilities Commission Decision (D) 24-01-032 approved the expansion of two demand flexibility pilots in PG&E's service area that ~~would~~ allow CCA participation. Under the Transportation Electrification Rulemaking 18-12-006, the CPUC further authorized PG&E's vehicle-to-grid (VGI) pilots with a dynamic rate that allow CCA participation. MCE is currently ~~evaluating whether it may participate beginning in the Summer of 2025~~offering all three pilots to its customers.

[10] The MCE Sync Dynamic Rewards pilot allows customers the chance to receive additional savings in MCE Sync by responding to dynamic hourly price signals (based on day-ahead CAISO prices for the PG&E Default Load Aggregation Point (DLAP). Customers who enroll in the dynamic pilot will receive an enrollment bonus of $50 and then receive a monthly reward payment for allowing MCE Sync to charge their car according to the dynamic price signal.

~~2025.~~adopted in Section 1623.1(b)(2). MCE will provide updates to its Board in its next plan iteration and any annual reports.

a. Cost-Effectiveness

In determining whether to offer dynamic rates that vary at least hourly as outlined in the LMS, one evaluation factor that MCE will consider is cost-effectiveness.

MCE notes that the CEC's adopted LMS state there shall be no reimbursement to local government agencies for the costs of carrying out the Standards as the Commission has found them to be cost effective, noting that savings realized will outweigh the costs associated with implementing the programs.[11] While MCE appreciates the plain language of the LMS, MCE disagrees that the cost-effectiveness of any rates or programs could be determined before those rates or programs actually exist. At this point there exists no evidence to conclude that MCE will realize any net savings from implementing the LMS. ~~MCE has not yet offered any~~It is too early in MCE's offering of hourly or dynamic rates or pilot programs to allow for sufficient analysis of the effectiveness (cost or otherwise) of dynamic rates in its service area. MCE has so far incurred only costs associated with the LMS and any benefits remain to be realized.

Nonetheless, MCE shares many of the CEC's stated goals in developing the LMS and is committed to encouraging customers to shift energy consumption to off-peak periods. MCE appreciates and understands that there may be significant value in dynamic rates and is interested in collecting the necessary information and data to determine if, and under what conditions, dynamic rates would be cost effective for MCE and its customers.

~~At present~~As of September 2024, MCE ~~is exploring the possibility of creating~~implemented an hourly rate pilot for its electric vehicle ("EV") customers, ~~as well as~~MCE Sync Dynamic Rewards.[12] MCE is also participating in, monitoring, and evaluating the status of CPUC approved PG&E dynamic rate pilots~~ and considering participation for Summer 2025~~. However, without such primary data, MCE cannot at this time determine that such a rate or program will provide material incremental reductions to peak load or be cost effective for any customer class.

Significant uncertainties remain in both the cost to develop and the value MCE can reliably realize from implementing hourly rates. MCE anticipates that developing dynamic rates may result in significant costs and MCE's ability to realize the value of such rates will be determined by unknown factors like customer adoption and incremental response levels. Without robust pilot results in MCE's and PG&E's service area to perform a comprehensive analysis, MCE cannot accurately estimate development costs, the estimated total benefits, or whether those benefits would be likely to offset the costs for any customer class. Accordingly, MCE recommends the Board not require MCE to propose dynamic rate to its Board by the target date of July 1, 2025.

[11] CEC Load Management Standards Section 1623.1(e).

[12] See footnote 10.

MCE recommends the Board find that MCE may, but is not required to, propose such a rate by the target date.

MCE will continue to evaluate whether to offer future dynamic rate pilots and rates to its customers and will evaluate the results of ~~any~~ its own pilot and the pilots in PG&E's service area. ~~To the extent MCE does participate in or offer dynamic rate pilots,~~ MCE will use the ~~pilot(s)~~pilots as an opportunity to collect the data necessary to conduct its own cost-effectiveness analysis with MCE specific data, which would be used to inform future rate and program offerings as well as future iterations of MCE's LMS Plan.

In conducting such a future cost-effectiveness analysis, MCE expects to compare the benefits of the rate offering with costs of implementation. Estimated costs include but are not limited to rate development, rate and program administration, and technology costs. Estimated benefits include, but are not limited to, lower energy costs, increased load reduction, avoided energy and capacity costs, and reliability benefits. To demonstrate cost-effectiveness, the expected benefits for each rate must exceed the costs of implementation. MCE looks forward to providing updates to its Board, the CEC, and other interested parties as it moves forward.

b. Equity

Similarly to cost-effectiveness, MCE currently has no primary data sources to quantitatively speak to the equity component of offering hourly rates to its customers. MCE is committed to increasing equitable and affordable access to clean energy for its customers. While reductions in peak demand provide grid benefits to all customers and those benefits could theoretically lower power procurement costs to all customers, currently there is not clear evidence that all MCE customers will benefit from lower rates. As MCE begins to evaluate whether to offer hourly rates to all customers, several equity components will be considered including:

Equitable Access to Automation and Benefits

Customers' ability to benefit from highly differentiated rates is directly linked to their ability to respond to those rates. Customers that can automate portions of their load will be best equipped to respond to pricing signals and benefit through lower energy bills or performance-based payments. Therefore, equitable access to automation devices and technology will be critical in ensuring that all customers can benefit from these rates. As such, MCE Staff believes it is appropriate to explore ways to ensure that customers on dynamic rates can access automation technology in an equitable manner. MCE may therefore explore offering additional incentives to provide automation technology for low-income customers and/or those who live in disadvantaged communities or multi-family properties who may otherwise not be able to benefit from automated load shifting programs or dynamic rates.

Cost Shifting

Assuming any change in rate design is designed to collect the same total level of revenue from all customers (i.e. revenue requirement), any change to rate design or structure means that some customers will pay less and some customers will pay more – without any changes to their behavior.[13] This mathematical reality is often referred to as a cost shift, as costs are shifted from one group of ratepayers to another. When rate offerings are voluntary, or opt-in, there is a greater risk that customers will simply choose the rate which allows them to pay less without making any changes to their behavior. These customers who can elect to participate in a rate that will lower their costs (and shift costs to other customers within their class) without any changes in behavior can be referred to as structural benefactors.

In developing dynamic rates with the goal of encouraging customers to *change* their behavior and shift their energy consumption away from peak hours, one of MCE's goals will be to minimize the amount of cost shifting that occurs between customers, particularly due to structural benefactors. To do so, MCE will aim to ensure that customers on hourly rates are sufficiently able to respond to price signals, whether through automation and/or price signals that are strong enough to incent behavioral change.

Customer Location

With few exceptions, customers do not choose where they are located on the electrical grid. It is partly because of this fact that grid infrastructure and energy costs have historically been spread, or averaged, across all customers. For example, rural customers have not been charged different prices for energy than city dwelling customers and MCE customers in Concord have not paid more than MCE customers in San Rafael, despite the potential differences in costs to serve those customers at any point in time (for example, due to local grid constraints). With a move to dynamic rates and advances in technology, it may be possible to charge customers in the same rate class and on the same tariff at different rates at any point in time given their location on the grid.

In both the CEC's LMS Rulemaking and the CPUC's Demand Flexibility Proceeding, there has been discussion on the level of locational granularity that should be applied to hourly or sub-hourly rates. While MCE and others are likely to first utilize hourly rates that do not vary at a level more granular than the Default Load Aggregation Point, there has been discussion of rates that vary at more granular levels, such the circuit or transformer level. Essentially, this means that the level of local grid constraint can affect the rates a customer in that area pays for electricity. MCE believes this is an important equity concern that cannot be overlooked.

Local grid constraints vary based on grid infrastructure, design, and capacity constraints that are generally outside of any individual customer's control. The more locational granularity in rates, the more potential there is for equity issues to arise. To address this issue, evaluation should be done to ensure that dynamic pricing based on localized grid constraints does not particularly burden low-income residents or those in disadvantaged communities. MCE does not currently have data on how more granular locational variation in rates may impact equity but urges all California LSEs as well as the CEC and CPUC to work to ensure that certain customers are not unfairly harmed by future rate design simply due to their location on the grid.

c. Technological Feasibility

[13] This is at least true in the short-term. However, in the long-term material reductions/changes in behavior may lower the total revenue requirement and those cost savings could be passed through to all customers.

MCE expects that it is technically feasible to offer a dynamic hourly generation rate option by July 1, 2027, as outlined in the LMS, contingent upon PG&E providing revenue quality billing data to MCE on an hourly level or developing a reliable workaround. Current PG&E billing transactions do not include the hourly interval data which would be matched against hourly dynamic prices. MCE hopes that as PG&E develops CPUC approved hourly pricing pilots, this data will become available.

MCE notes that even if dynamic rates are technically feasible, daily rate uploads to MIDAS will need to be supported by the development of new systems, which may delay or otherwise impede offering dynamic rates in the near term. The limitations of the current MIDAS system and the lack of funding for LSEs to develop systems for interacting with MIDAS may mean that it will not be cost effective or feasible to maintain dynamic rates in MIDAS at this time.

d. Benefits to the Grid and Customers

MCE will also consider benefits to the grid and benefits to customers in its evaluation of dynamic rates. Assuming material changes in energy consumption behavior by customers, potential grid benefits resulting from hourly rates include but are not limited to reliability benefits, deferred, and reduced grid infrastructure investments, and environmental benefits.

Potential direct customer benefits include, but are not limited to, lower energy expenditures, reliability benefits, and theoretically lower rates – assuming material reductions to peak load that result in lower overall energy costs and reduced capacity and compliance costs. MCE does not currently have the data to quantify benefits to the grid and customers resulting from offering hourly rates in its service territory. MCE plans to continue to gather data on this topic and will update this section in future iterations of its plan and annual reports.

4.3 Dynamic Rate Development and Application Plan *– Amended July 2025*

Adopted LMS Amendments Section 1623.1(b)(2) of the LMS requests MCE and other Large CCAs apply to its rate-approving body for approval of at least one dynamic rate by July 1, 2025. The LMS state MCE should apply for approval of a dynamic rate only for those customer classes for which the Board determines such a rate will materially reduce peak load. This section outlines how MCE plans to work toward this goal.

MCE has been, and plans to remain, actively engaged in dynamic rates discussions and proceedings at the CPUC and CEC. To date, MCE has committed considerable staff time, which amounts to significant and material cost to MCE, to these efforts, including making staff available to attend all noticed CEC LMS working group meetings and engaging in the CPUC's Demand Flexibility proceeding. Additionally, MCE is conducting research internally and in collaboration with external partners on how it might best design and offer dynamic rates in the future.

MCE is committed to exploring options for offering dynamic rate offerings to customers, but at this time cannot determine that such rates would provide material incremental reductions to peak load, provide other material benefits to MCE or its customers, or be cost effective for any customer class. In evaluating future potential dynamic rates MCE will consider whether or how any dynamic rate is expected to: 1) drive behavioral change; 2) be cost effective; 3) impact equity outcomes; and 4) provide reliable incremental benefits relative to MCE's current rate offerings.

~~At present~~As of September 2024, MCE ~~is exploring the possibility of~~ began offering a dynamic rate pilot, MCE Sync Dynamic Rewards, for its electric vehicle ("EV") customers~~, as well as~~. MCE is also participating in, monitoring, and evaluating the status of CPUC approved PG&E dynamic rate pilots~~ and considering participation for Summer 2025~~. However, without such primary data, MCE cannot at this time determine that such a rate or program will provide material incremental reductions to peak load or be cost effective for any customer class.

Significant uncertainties remain in both the cost to develop and the value MCE can reliably realize from implementing hourly rates. MCE anticipates that developing dynamic rates may result in significant costs and MCE's ability to realize the value of such rates will be determined by unknown factors like customer adoption and incremental load shifting response levels. Without robust pilot results in MCE's and PG&E's service area to perform a comprehensive analysis, MCE cannot accurately estimate development costs, the estimated total benefits, or whether those benefits would be likely to offset the costs. Accordingly, MCE recommends the Board not require MCE to propose a dynamic, hourly marginal cost-based rate, to its Board by the target date of July 1, 2025. MCE recommends the Board modify the request in LMS Section 1623.1(b)(2) that MCE propose dynamic rates by July 1, 2025, and declare that MCE may, but is not required to, propose such a rate to the Board for approval by July 1, 2025.

MCE will continue to evaluate if and how it may offer dynamic rates to its customers and will provide updates to its Board in its next plan iteration and any annual reports, and looks forward to continuing conversation and collaboration with stakeholders on possible pilot design, including how best to collect data that will effectively illustrate the costs and benefits of different dynamic rate structures and incorporate rates into MIDAS.

Additionally, LMS Section 1623.1(b)(4) requests MCE offer customers voluntary participation in either a dynamic rate, if approved by the Board, or a cost-effective load flexibility program by July 1, 2027. MCE notes that its offerings as of July 1, 2027, cannot be known at present, and the future timeline for deployment of future rate and program offerings will be dependent on future Board guidance and approval.

MCE plans to continue to provide updates to its Board as well as the CEC, as outlined in the LMS, and will further address the details of rate design and infrastructure needs as they become available.

5 Load Flexibility Programs

Adopted LMS Amendments Section 1623.1(b)(3) of the LMS requests MCE submit a list of cost-effective load flexibility programs to the CEC Executive Director by October 1, 2024. The portfolio of load flexibility programs is to provide at least one option to automate response to MIDAS signals for every customer class where such a program is determined by the Board to materially reduce peak load. If MCE's Board does not approve of and offer dynamic rates by July 1, 2027, the Standards state that MCE can meet the goals of the LMS by offering voluntary participation in a cost-effective MIDAS-integrated load flexibility program.

This section of MCE's Plan provides an overview of MCE's current load flexibility programs and addresses how MCE will evaluate and propose specified programs on the timeframes set forth in the LMS.

5.1 Overview of MCE Load Flexibility Programs

Residential Programs

MCE Sync

MCE Sync is an MCE-funded Automated Load Management program that utilizes a smart charging app to reduce EV owner's charging load during peak times, while also seeking to align EV charging load with high-solar daytime hours.[14] MCE began offering MCE Sync to eligible customers in 2021 and the program offers customers a flat monthly credit for participating in events.

Through 2023, MCE Sync had approximately 2,200 enrolled MCE customers who charge their EVs at home via a software platform which delivers direct load control of EV charging using vehicle telematics and networked electric vehicle supply equipment. To date, the program has shifted 90 percent of EV charging events out of the 4 pm – 9 pm window. An analysis of program data through May 2022 showed that customers saved an average of $10 shifting charging to off-peak hours.

MCE Sync does not currently have rates associated with events. MCE Staff are currently exploring the possibility of expanding the program in MCE's service area, including integrating dynamic pricing elements into future program offerings.

Peak FLEXmarket

MCE's Peak FLEXmarket program is a market-driven demand flexibility program that assigns an hourly value to measured, behind-the-meter ("BTM") impacts.[15] Peak FLEXmarket is aimed at shifting load away from peak periods and provides customers with direct payments for measured load shedding or shifting during events, based on deviations from their individual baseline.

Peak FLEXmarket has successfully engaged new aggregators who have not participated in demand response, as well as program partners who have traditionally been confined to energy efficiency project development by presenting a value proposition for load flexibility. This program is a framework with the tools to measure and value hourly reductions in energy use and is technology agnostic.

Richmond Virtual Power Plant (VPP) Pilot

MCE is working to launch an innovative VPP pilot in Richmond, California, which will provide bill savings and increase local grid reliability, safety, and efficiency for low-income residents as part of Richmond's Advanced Energy Community project.[16] The VPP pilot includes $8 million in funding from the CEC and will provide a suite of clean distributed energy resources ("DERs") targeting low-income households in Richmond for dispatchability, flexibility, and resiliency purposes.

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[14] *See* https://www.mcecleanenergy.org/mce-sync/.
[15] *See* https://www.mcecleanenergy.org/peak-flexmarket/.
[16] *See* http://mcecleanenergy.org/vpp.

MCE's Richmond VPP Pilot is expected to provide significant bill savings for customers and significant local and grid benefits. MCE currently expects the pilot to launch in 2025.

Residential Efficiency Market

MCE's Residential Efficiency Market program is focused on incentivizing customers to install measures that can help reduce peak load.[17] Customers can receive a 20 percent upfront cash payment for the forecasted value of their energy efficiency projects and additional payments for metered savings of those energy efficiency projects.

Solar Storage Credit

MCE's Solar Storge Credit program is aimed at encouraging customers to discharge their energy storage systems from 4-9pm daily.[18] To be eligible for the credit, customers must be enrolled in a time-of-use rate, automate their battery to discharge from 4-9 p.m. daily and set their battery reserve to no more than 20 percent, except when preparing for or during a power outage. Customers are eligible to receive up to $20/month for participation based on their solar system's size.

Nonresidential Programs

Peak FLEXmarket

MCE's Peak FLEXmarket program is a market-driven demand flexibility program that assigns an hourly value to measured BTM impacts. Peak FLEXmarket is aimed at shifting load away from peak periods and provides customers with direct payments for measured load shedding or shifting during events, based on deviations from their individual baseline.

Peak FLEXmarket has successfully engaged new aggregators who have not participated in demand response, as well as program partners who have traditionally been confined to energy efficiency project development by presenting a value proposition for load flexibility. This program is a framework with the tools to measure and value hourly reductions in energy use and is technology agnostic.

Commercial Efficiency Market

MCE's Commercial Efficiency Market program is focused on incentivizing non-residential customers to install measures that can help reduce peak load.[19] Customers can receive a 20 percent upfront cash payment for the forecasted value of their energy efficiency projects and additional payments for metered savings of those energy efficiency projects.

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[17] *See* https://www.mcecleanenergy.org/flexmarket/.
[18] *See* https://www.mcecleanenergy.org/solar-storage-credit/.
[19] *See* https://www.mcecleanenergy.org/flexmarket/.

5.2 Evaluation of Programs

This section evaluates the cost-effectiveness, equity, technological feasibility, and benefits to the grid and customers of implementing programs that enable automated response to MIDAS signals. As discussed below, MCE cannot currently conclude that creating a new, or modifying an existing, load-modifying program to allow automated responses to MIDAS signals would be cost effective or offer material incremental benefit, such as material incremental peak load reduction, for any customer class.

Accordingly, MCE will continue to offer voluntary participation in its existing and future load flexibility programs. MCE will continue to consider the cost-effectiveness and peak load reduction potential of programs that enable automated response to MIDAS signals. To the extent that MCE's Board does not approve a dynamic rate offering by 2027, *and* MCE is at that time able to determine that modifying an existing program or creating a new program that enables automated response to MIDAS signals is cost effective and provides material incremental reductions to peak load for at least one customer class, MCE may at that time integrate a load-modifying program into MIDAS.

MCE will therefore submit to the CEC a list of load-modifying programs deemed cost-effective by October 1, 2024, but recommends the Board find that MCE is not required to include a program that allows automated response to MIDAS signals as it cannot determine such a program would be cost effective or produce material reductions to peak load for any customer class.

5.2.1 Cost Effectiveness

As outlined by section 1623.1(b)(3) of the LMS, MCE will provide a list of load-modifying programs deemed cost effective to the CEC by October 1, 2024. At present, MCE expects that the list of cost-effective programs will include the following MCE load-modifying programs:

1. Peak FLEXmarket;
2. Commercial Efficiency Market; and
3. Residential Efficiency Market.

These programs are funded by ratepayers through MCE's Energy Efficiency Portfolio as authorized by the CPUC. To receive ratepayer funding, the CPUC requires MCE to demonstrate its energy efficiency portfolio is cost effective using CPUC-approved cost-effectiveness criteria.

As it relates to the cost-effectiveness of MCE's current and future self-funded and/or grant-funded load-modifying programs (MCE Sync, Solar Storage Credit, Richmond VPP Pilot, etc.) MCE has not yet evaluated these programs for cost-effectiveness in the same manner as its ratepayer funded energy efficiency programs. Generally, MCE notes that cost-effectiveness is just one measure used to determine whether to offer a program and is not necessarily a determining factor. For example, programs that are focused on providing equity benefits may not be cost-effective utilizing traditional cost-effectiveness evaluation criteria, but still provide significant benefit to certain customer segments and society at large. MCE may robustly evaluate these programs for cost-effectiveness in the future when evaluating the effectiveness of the programs, and as it makes future determinations on program offerings.

MCE does not currently expect to utilize program offerings with automated responses to MIDAS signals; however, if MCE's Board does not adopt an hourly rate by July 1, 2027, MCE may then evaluate whether there is an opportunity to create a new program or modify an existing program to allow responses to MIDAS signals. In doing so, MCE would look at the incremental value of each option, and if modifying an existing, or creating a new, program is deemed cost-effective and found to provide material reductions to peak load may elect to do so at that time.

MCE cannot currently conclude that the modification of current or development of new programs that allow for automated responses to dynamic price signals would be cost effective for any customer class. Developing new programs or modifying existing programs would require MCE to incur costs associated with design and implementation, along with new technology costs. While these costs could potentially be offset with capacity or energy cost savings, the magnitude of those benefits is uncertain.

In conducting future cost-effectiveness analyses, MCE would compare expected program benefits to expected costs of program design and implementation. Assuming incremental load shift that can be attributed to the program, expected benefits of a new load flexibility program that allows for automated response to MIDAS signals may include, but are not limited to, avoided energy and capacity costs, improved reliability, and environmental benefits. Expected costs may include, but are not limited to, program development costs, program administration costs, and technology and implementation costs.

5.2.2 Equity

MCE is committed to creating more equitable communities and providing equitable access to clean energy benefits throughout its service area. In choosing to modify or offer any program, MCE carefully considers equity impacts and has demonstrated its commitment to equitable program offerings since its inception. MCE aims to offer a suite of programs that provide customers with access to clean energy technology and services while lowering bills and greenhouse gas emissions. Some examples of MCE's commitment to equity include MCE's:

1. Income-qualified customer programs such as the Low-Income Families and Tenants Program, the MCE Cares Credit Program, DAC-GT program, and EV Rebate Program;
2. Commercial Equity Program;
3. Commitment to advancing supplier diversity and workforce development; and
4. MCE's Community Power Coalition.[20]

In evaluating any future load-modifying program offerings, MCE will plan to evaluate how that offering may impact customer equity. Potential evaluation criteria include, but are not limited to, equitable access to technology, direct customer benefits and bill impacts, and cost-shifting between and within rate classes. For example, most customers' ability to benefit from highly differentiated rates will be directly linked to their ability to respond to those rates. Customers that can automate portions of their load will be best equipped to respond and benefit. Therefore, equitable access to automation devices and technology will be critical in ensuring that all

[20] More information on MCE's energy equity efforts can be found on its website at https://www.mcecleanenergy.org/energy-equity/#energyequity.

customers can benefit from load-modifying programs. To promote equitable access to automation technology MCE may explore providing additional incentives for low-income customers and/or those who located in disadvantaged communities or multi-family properties who may otherwise not be able to benefit from automated load shifting programs or dynamic rates.

5.2.3 Technological Feasibility

MCE is committed to offering load-modifying programs that encourage customers to shift their load away from periods of grid constraint and high greenhouse gas emissions. MCE strongly supports the LMS' goals to provide customers and their devices access to signals that may help automate their response to marginal signals such as prices and greenhouse gas signals to provide the greatest level of benefit for both the customer and the grid. MCE has demonstrated this support through the development of its MCE Sync EV charging mobile application and the MCE Peak FLEXmarket platform, both of which are technology platforms that help customers adjust their energy consumption through greater visibility. And while MCE believes it is technically feasible to offer customers programs that allow customers to respond to MIDAS signals, currently, both of these load-modifying programs are incompatible with the MIDAS database, and MCE cannot conclude that modifying them to be compatible would be cost effective or result in material incremental load reduction:[21]

- MCE Sync - This program provides a flat monthly credit to customers for participating in events, and does not have rates associated with events, and thus would not support inclusion in MIDAS.
- PeakFLEX Market - There is currently no way for MIDAS to show customers their current real-time rate for this program, as it is based on separate prices (baseline and above-baseline) that depend on a customers' individual usage history, which is not a component of MIDAS.

As MCE's existing load-modifying programs are not currently technologically compatible with MIDAS, if MCE at a later date elects to work towards the goals of the LMS via a MIDAS enabled program offering MCE would need to determine how it could either integrate its existing programs with MIDAS or explore the creation of a new program that would be compatible with the current or future design of MIDAS. Such determinations will need to be made by the Board at a future date.

[21] While not a load-modifying program, MCE also notes that its Disadvantaged Community Green Tariff program is also not included in MIDAS currently as it is not compatible with the current design of MIDAS. The 20 percent bill discount for the DAC-GT program is calculated from a customer's total billed charges, inclusive of non-volumetric and variable IOU charges, by reading the total charges from the previous bill. As such, MCE cannot generate a volumetric price inclusive of this discount.

5.2.4 Benefits to the Grid and Customers

In considering whether to modify existing or offer new load-modifying programs, including those that allow automated response to MIDAS signals, MCE may consider benefits to the grid and customers.

Assuming incremental load shift or reduction that can be attributed to the program, potential grid benefits include reduced capacity costs (for example through lower Resource Adequacy costs), reduced of deferred transmission and distribution system upgrades, lower energy costs, increased reliability benefits, and environmental benefits.

Assuming incremental load shift or reduction that can be attributed to the program, potential customer benefits include pass-through energy cost savings from grid benefits as well as pass-through cost savings from potential reduced compliance costs for MCE, improved reliability, improved environmental benefits, and direct cost savings from participation in load-modifying programs.

All of these potential grid and customer benefits depend on the reliability and magnitude of load shift and reduction that load-modifying programs are able to achieve. MCE is at this time unable to conclude that future programs or modifications to existing programs to allow automated responses to MIDAS signals would result in material grid benefits relative to MCE's existing offerings or result in pass through savings to customers for any customer class. If MCE creates a load-modifying program that allows automated response to MIDAS signals in the future it will aim to design the program in such a way to generate material benefits to the grid and MCE customers.

6 Public Information Program

Adopted LMS Amendments Section 1623.1(b)(5) of the LMS requests MCE and other Large CCAs to conduct a public information program to inform and educate affected customers on why dynamic rates or load flexibility programs and automation are needed, how they will be used, and how these rates and programs can save customers money.

MCE appreciates the LMS' intent to ensure that any load-modifying rates or programs developed are effectively marketed to customers with the aim of encouraging enrollment and maximizing customer success and grid benefits. As a local, community-based organization, MCE values and is deeply committed to providing quality customer and community communication, education, collaboration, and customer service.

As a general matter, all MCE rates and programs can be found on MCE's website. Any future dynamic rates or load-modifying programs will also be listed and described on its webpage.[22] MCE utilizes best practices to provide consistent and accurate communications and response support with its customers and communities. This includes utilizing various communication mediums including joint rate mailers, emails, direct mail, e-newsletters, press releases, webinars,

[22] MCE Residential rates can be viewed at https://www.mcecleanenergy.org/rates/. MCE Commercial rates can be viewed at https://www.mcecleanenergy.org/commercial-rates/. MCE program offerings can be found at https://www.mcecleanenergy.org/customer-programs/.

social media posts, public presentations and event attendance and sponsorship throughout MCE's member communities. In 2023 alone, MCE attended more than 250 events in our service area and presented to 69 local community organizations and city councils. MCE plans to continue communication best practices to maintain its outreach, education, and marketing of rates, programs, and pilots that support load flexibility and recognize the benefits of reducing peak load and using energy during periods of higher renewables supply. In addition, MCE has developed an in-house service center to support and effectively respond to customer inquiries and further the education and benefits of load-modifying programs.

Historically, MCE has voluntarily utilized various types of marketing campaigns to drive enrollment and successful participation in rate and program offerings including those created for load-modifying purposes. For example, to encourage customers to shift load on Time-of-Use rates, MCE conducted a public information campaign that included direct mail, website updates, digital advertising, streaming, and radio placement encouraging customers to use less energy during the 4pm - 9pm peak period targeted to customers throughout MCE's service area.[23]

MCE notes that the LMS do not include a timeline for the public information campaign. As there is no timeline expressed in the Standards and MCE has not created or recommended Board approval of any new hourly marginal cost-based rates or programs that allow automated response to MIDAS signals, MCE does not have details on what future public information programs may entail. MCE expects that if dynamic rates or new load flexibility programs are adopted MCE would utilize a public information program to drive customer adoption, understanding, and success in said rates or programs.

At a minimum, MCE would expect the public information program to highlight how individual customers may be impacted (i.e. bill impacts) and how changes to their behavior can create grid and/or environmental benefits for all customers. This type of public information program would utilize some or all the following communication mediums: direct mail, email correspondence, website updates, social media posts, webinars, television/streaming commercials, press releases or news articles, and public presentations. MCE may also work with its community partners and/or program and technology partners to develop and deliver any public information programs.

MCE expects that any public information campaign would require incremental costs that are not currently accounted for, and MCE would need to factor these public information and response program costs and their recovery into any cost-effectiveness analysis and recommendation to its Board.

[23] *See* https://www.mcecleanenergy.org/4-9/.

7 Appendix

Appendix A – MCE MIDAS Rate Identification Numbers

The below table displays the RINs associated with each of MCE's residential and non-residential rates and rate permutations that have been uploaded to MIDAS.

RIN	Rate Schedule	Energy Supply Product
USCA-XXMC-PBZD-0000	ETOUB	Deep Green
USCA-XXMC-PCZD-0000	ETOUC	Deep Green
USCA-XXMC-PDZD-0000	ETOUD	Deep Green
USCA-XXMC-OZZD-0000	ELEC	Deep Green
USCA-XXMC-QAZD-0000	EVA	Deep Green
USCA-XXMC-QUZD-0000	EV2	Deep Green
USCA-XXMC-AXZD-0000	A1X	Deep Green
USCA-XXMC-EZZD-0000	B1	Deep Green
USCA-XXMC-ETZD-0000	B1ST	Deep Green
USCA-XXMC-CZZD-0000	A6	Deep Green
USCA-XXMC-IZZD-0000	B6	Deep Green
USCA-XXMC-BXCD-0000	A10SX	Deep Green
USCA-XXMC-FZCD-0000	B10S	Deep Green
USCA-XXMC-BXBD-0000	A10PX	Deep Green
USCA-XXMC-FZBD-0000	B10P	Deep Green
USCA-XXMC-BXDD-0000	A10TX	Deep Green
USCA-XXMC-FZDD-0000	B10T	Deep Green
USCA-XXMC-LZCD-0000	E19S	Deep Green
USCA-XXMC-GZCD-0000	B19S	Deep Green
USCA-XXMC-LZBD-0000	E19P	Deep Green
USCA-XXMC-GZBD-0000	B19P	Deep Green
USCA-XXMC-LZDD-0000	E19T	Deep Green
USCA-XXMC-GZDD-0000	B19T	Deep Green
USCA-XXMC-LRCD-0000	E19SR	Deep Green
USCA-XXMC-GRCD-0000	B19SR	Deep Green
USCA-XXMC-LRBD-0000	E19PR	Deep Green
USCA-XXMC-GRBD-0000	B19PR	Deep Green
USCA-XXMC-LRDD-0000	E19TR	Deep Green
USCA-XXMC-GRDD-0000	B19TR	Deep Green
USCA-XXMC-MZCD-0000	E20S	Deep Green
USCA-XXMC-HZCD-0000	B20S	Deep Green
USCA-XXMC-MZBD-0000	E20P	Deep Green
USCA-XXMC-HZBD-0000	B20P	Deep Green

RIN	Rate Schedule	Energy Supply Product
USCA-XXMC-MZDD-0000	E20T	Deep Green
USCA-XXMC-HZDD-0000	B20T	Deep Green
USCA-XXMC-MRCD-0000	E20SR	Deep Green
USCA-XXMC-HRCD-0000	B20SR	Deep Green
USCA-XXMC-MRBD-0000	E20PR	Deep Green
USCA-XXMC-HRBD-0000	B20PR	Deep Green
USCA-XXMC-MRDD-0000	E20TR	Deep Green
USCA-XXMC-HRDD-0000	B20TR	Deep Green
USCA-XXMC-DAED-0000	AGA1	Deep Green
USCA-XXMC-DAFD-0000	AGA2	Deep Green
USCA-XXMC-DBZD-0000	AGB	Deep Green
USCA-XXMC-DCZD-0000	AGC	Deep Green
USCA-XXMC-DGED-0000	AGFA1	Deep Green
USCA-XXMC-DGFD-0000	AGFA2	Deep Green
USCA-XXMC-DGGD-0000	AGFA3	Deep Green
USCA-XXMC-DHED-0000	AGFB1	Deep Green
USCA-XXMC-DHFD-0000	AGFB2	Deep Green
USCA-XXMC-DHGD-0000	AGFB3	Deep Green
USCA-XXMC-DIED-0000	AGFC1	Deep Green
USCA-XXMC-DIFD-0000	AGFC2	Deep Green
USCA-XXMC-DIGD-0000	AGFC3	Deep Green
USCA-XXMC-DJZD-0000	AG4A	Deep Green
USCA-XXMC-DKZD-0000	AG4B	Deep Green
USCA-XXMC-DLZD-0000	AG4C	Deep Green
USCA-XXMC-DMZD-0000	AG5A	Deep Green
USCA-XXMC-DNZD-0000	AG5B	Deep Green
USCA-XXMC-DOZD-0000	AG5C	Deep Green
USCA-XXMC-TZCD-0000	STOUS	Deep Green
USCA-XXMC-TZBD-0000	STOUP	Deep Green
USCA-XXMC-TZDD-0000	STOUT	Deep Green
USCA-XXMC-SZCD-0000	SBS	Deep Green
USCA-XXMC-SZBD-0000	SBP	Deep Green
USCA-XXMC-SZDD-0000	SBT	Deep Green
USCA-XXMC-JZED-0000	BEV1	Deep Green
USCA-XXMC-JUCD-0000	BEV2S	Deep Green
USCA-XXMC-JUBD-0000	BEV2P	Deep Green
USCA-XXMC-NZZD-0000	E6	Deep Green
USCA-XXMC-PBZL-0000	ETOUB	Light Green
USCA-XXMC-PCZL-0000	ETOUC	Light Green
USCA-XXMC-PDZL-0000	ETOUD	Light Green
USCA-XXMC-OZZL-0000	ELEC	Light Green

RIN	Rate Schedule	Energy Supply Product
USCA-XXMC-QAZL-0000	EVA	Light Green
USCA-XXMC-QUZL-0000	EV2	Light Green
USCA-XXMC-AXZL-0000	A1X	Light Green
USCA-XXMC-EZZL-0000	B1	Light Green
USCA-XXMC-ETZL-0000	B1ST	Light Green
USCA-XXMC-CZZL-0000	A6	Light Green
USCA-XXMC-IZZL-0000	B6	Light Green
USCA-XXMC-BXCL-0000	A10SX	Light Green
USCA-XXMC-FZCL-0000	B10S	Light Green
USCA-XXMC-BXBL-0000	A10PX	Light Green
USCA-XXMC-FZBL-0000	B10P	Light Green
USCA-XXMC-BXDL-0000	A10TX	Light Green
USCA-XXMC-FZDL-0000	B10T	Light Green
USCA-XXMC-LZCL-0000	E19S	Light Green
USCA-XXMC-GZCL-0000	B19S	Light Green
USCA-XXMC-LZBL-0000	E19P	Light Green
USCA-XXMC-GZBL-0000	B19P	Light Green
USCA-XXMC-LZDL-0000	E19T	Light Green
USCA-XXMC-GZDL-0000	B19T	Light Green
USCA-XXMC-LRCL-0000	E19SR	Light Green
USCA-XXMC-GRCL-0000	B19SR	Light Green
USCA-XXMC-LRBL-0000	E19PR	Light Green
USCA-XXMC-GRBL-0000	B19PR	Light Green
USCA-XXMC-LRDL-0000	E19TR	Light Green
USCA-XXMC-GRDL-0000	B19TR	Light Green
USCA-XXMC-MZCL-0000	E20S	Light Green
USCA-XXMC-HZCL-0000	B20S	Light Green
USCA-XXMC-MZBL-0000	E20P	Light Green
USCA-XXMC-HZBL-0000	B20P	Light Green
USCA-XXMC-MZDL-0000	E20T	Light Green
USCA-XXMC-HZDL-0000	B20T	Light Green
USCA-XXMC-MRCL-0000	E20SR	Light Green
USCA-XXMC-HRCL-0000	B20SR	Light Green
USCA-XXMC-MRBL-0000	E20PR	Light Green
USCA-XXMC-HRBL-0000	B20PR	Light Green
USCA-XXMC-MRDL-0000	E20TR	Light Green
USCA-XXMC-HRDL-0000	B20TR	Light Green
USCA-XXMC-DAEL-0000	AGA1	Light Green
USCA-XXMC-DAFL-0000	AGA2	Light Green
USCA-XXMC-DBZL-0000	AGB	Light Green
USCA-XXMC-DCZL-0000	AGC	Light Green

RIN	Rate Schedule	Energy Supply Product
USCA-XXMC-DGEL-0000	AGFA1	Light Green
USCA-XXMC-DGFL-0000	AGFA2	Light Green
USCA-XXMC-DGGL-0000	AGFA3	Light Green
USCA-XXMC-DHEL-0000	AGFB1	Light Green
USCA-XXMC-DHFL-0000	AGFB2	Light Green
USCA-XXMC-DHGL-0000	AGFB3	Light Green
USCA-XXMC-DIEL-0000	AGFC1	Light Green
USCA-XXMC-DIFL-0000	AGFC2	Light Green
USCA-XXMC-DIGL-0000	AGFC3	Light Green
USCA-XXMC-DJZL-0000	AG4A	Light Green
USCA-XXMC-DKZL-0000	AG4B	Light Green
USCA-XXMC-DLZL-0000	AG4C	Light Green
USCA-XXMC-DMZL-0000	AG5A	Light Green
USCA-XXMC-DNZL-0000	AG5B	Light Green
USCA-XXMC-DOZL-0000	AG5C	Light Green
USCA-XXMC-TZCL-0000	STOUS	Light Green
USCA-XXMC-TZBL-0000	STOUP	Light Green
USCA-XXMC-TZDL-0000	STOUT	Light Green
USCA-XXMC-SZCL-0000	SBS	Light Green
USCA-XXMC-SZBL-0000	SBP	Light Green
USCA-XXMC-SZDL-0000	SBT	Light Green
USCA-XXMC-JZEL-0000	BEV1	Light Green
USCA-XXMC-JUCL-0000	BEV2S	Light Green
USCA-XXMC-JUBL-0000	BEV2P	Light Green
USCA-XXMC-NZZL-0000	E6	Light Green

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

Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes.	R.25-06-019

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE ORDER INSTITUTING RULEMAKING

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Lauren Carr,
Senior Manager, Regulatory Affairs and Market Policy
Eric Little,
Director of Market Design

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

August 1, 2025

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  - The IRP proceeding should be the primary venue for ongoing Commission coordination with other regulatory agencies and the CAISO, including:
    - Working with the CEC to ensure load forecast accuracy and establish a process for load forecasting that recognizes the uncertainty of large load energizations;
    - In coordination with the CAISO, reforming transmission planning tools and decision-making processes to account for uncertainty and ensure a competitive market;
    - Holding a public stakeholder process with the CAISO to address FERC Order 1920;
    - Coordinating with the CAISO on a process to ensure reliable delivery of OOS resources under long-term contract;
    - Evaluating renewable curtailments with the CAISO to ensure PSP modeling accurately reflects congestion;
    - Considering, along with the CAISO, how to adjust the long-term planning process to ensure reliability as reliability needs shift;
  - A standing track in the IRP proceeding to examine the large IOU BPPs;
  - The Commission should evaluate how to ensure that load can be reliably served with a reduced reliance on gas resources in the most cost-effective manner;
  - The Commission should evaluate how to reduce reliance on gas resources currently needed to serve load in local areas;
  - The Aliso Canyon constraint should be embedded in models used to develop the PSP portfolios;
  - The OIR's "Coordination with DWR on LLT Resource Procurement" scope item should be updated to include the establishment of a procurement group and details of cost-benefit allocation; and
  - The Commission should develop a more structured waiver process for MTR obligations.

- Schedule Recommendations:
    - Individual LSE IRP plans should be due no earlier than February 2026, but no sooner than six months after the I&A and compliance guidelines are issued;
    - The Commission should establish the schedule and cadence of LSE procurement compliance filings when developing RCPPP, rather than within the OIR; and
    - The Commission should use this proceeding to develop the reliability and GHG-reduction RCPPP frameworks in two tracks.

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

Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes.	R.25-06-019

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE ORDER INSTITUTING RULEMAKING**

The California Community Choice Association[1] (CalCCA) submits these comments pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure[2] on the *Order Instituting Rulemaking*[3] (OIR), issued July 2, 2025, and the directives therein. The OIR will be the new primary venue for the Commission's oversight of the Integrated Resources Planning (IRP) process, which was designed in R.16-02-007, and continued in R.20-05-003.

I. INTRODUCTION

This new rulemaking proceeding will be instrumental in influencing the state's ability to ensure reliable, cost-effective, and clean electricity supply for Californians. The proceeding will

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

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

[3] *Order Instituting Rulemaking,* Rulemaking (R.) 25-06-019 (July 2, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K276/571276511.PDF.

address key elements of long-term electricity planning essential for managing California's complex transition towards the implementation of SB 350[4] and SB 100[5] in a reliable and affordable manner. The OIR advances the preliminary scope and schedule for the planning and procurement activities that will take place in the IRP process in the coming years, including: (1) consideration of individual load-serving entity (LSE) IRPs; (2) development of preferred system plan (PSP) portfolios and transmission planning process (TPP) recommendations; (3) potential implementation of the pending reliable and clean power procurement program (RCPPP); (4) monitoring and enforcing compliance with past procurement orders; and (5) coordinating with the California Department of Water Resources (DWR) on long-lead time (LLT) resource procurement.

The comments herein provide the following recommendations on the OIR's preliminary scope and schedule:

- Scope Recommendations:
  - The IRP proceeding should be the primary venue for ongoing Commission coordination with other regulatory agencies and the California Independent System Operator (CAISO), including:
    - Working with the California Energy Commission (CEC) to ensure load forecast accuracy and establish a process for load forecasting that recognizes the uncertainty of large load energizations;
    - In coordination with the CAISO, reforming transmission planning tools and decision-making processes to account for uncertainty and ensure a competitive market;
    - Holding a public stakeholder process with the CAISO to address FERC Order 1920;[6]

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4 Senate Bill (SB) 350 (De León, Chapter 547, Statutes of 2015).
5 SB 100 (De León, Chapter 312, Statutes of 2018).
6 Federal Energy Regulatory Commission (FERC) Order 1920 (May 13, 2024): https://www.ferc.gov/news-events/news/fact-sheet-building-future-through-electric-regional-transmission-planning-and; and FERC Order 1920-A (Nov. 21, 2024): https://www.ferc.gov/news-events/news/ferc-strengthens-order-no-1920-expanded-state-provisions.

        - Coordinating with the CAISO on a process to ensure reliable delivery of out-of-state (OOS) resources under long-term contract;

        - Evaluating renewable curtailments with the CAISO to ensure PSP modeling accurately reflects congestion;

        - Considering, along with the CAISO, how to adjust the long-term planning process to ensure reliability as reliability needs shift;

    - A standing track in the IRP proceeding to examine the large investor-owned utilities' (IOU) bundled procurement plans (BPP);

    - The Commission should evaluate how to ensure that load can be reliably served with a reduced reliance on gas resources in the most cost-effective manner;

    - The Commission should evaluate how to reduce reliance on gas resources currently needed to serve load in local areas;

    - The Aliso Canyon constraint should be embedded in models used to develop the PSP portfolios;

    - The OIR's "Coordination with DWR on LLT Resource Procurement" scope item should be updated to include the establishment of a procurement group and details of cost-benefit allocation; and

    - The Commission should develop a more structured waiver process for mid-term reliability (MTR) obligations.

- Schedule Recommendations:

    - Individual LSE IRP plans should be due no earlier than February 2026, but no sooner than six months after the inputs and assumptions (I&A) and compliance guidelines are issued;

    - The Commission should establish the schedule and cadence of LSE procurement compliance filings when developing RCPPP, rather than within the OIR; and

    - The Commission should use this proceeding to develop the reliability and greenhouse gas (GHG)-reduction RCPPP frameworks in two tracks.

II. SCOPE RECOMMENDATIONS

CalCCA generally supports the OIR's preliminary scope with the following modifications described below.

A. The IRP Proceeding Should Be the Primary Venue for Ongoing Coordination with Other Regulatory Agencies and the CAISO

CalCCA supports the Commission's statement in the OIR that it will use the IRP proceeding as:

> [T]he primary venue for ongoing Commission-CAISO-CEC [memorandum of understanding (MOU)] coordination with the CEC's IEPR process, the CAISO's TPP and other transmission planning efforts, the Scoping Plan and Emissions Inventory processes of CARB, and the once-through cooling policies for power plant cooling of the State Water Resources Control Board (Water Board).[7]

As part of these coordination efforts, the Commission should: (1) work with the CEC to ensure load forecasting accuracy and establish a process for load forecasting that recognizes the uncertainty of large load energizations, given increasing impacts of electrification, large loads, load shifting, distributed energy resources (DER), and demand response (DR); (2) coordinate with the CAISO to reform transmission planning tools and decision-making processes to accommodate uncertainty and ensure a competitive market; (3) coordinate with the CAISO on a public stakeholder process to address FERC Order 1920; (4) coordinate with the CAISO to ensure reliable delivery of OOS resources under long-term contract; (5) evaluate with the CAISO renewable curtailments to ensure PSP modeling correctly reflects congestion; (6) consider, along with the CAISO, how to adjust long-term planning processes to ensure reliability as reliability needs shift.

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[7] OIR, at 10; *see also Memorandum of Understanding Between the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) and the California Independent System Operator (ISO) Regarding Transmission and Resource Planning and Implementation* (Dec. 23, 2022) (MOU): https://www.energy.ca.gov/sites/default/files/2023-01/MOU_Dec_2022_CPUC_CEC_ISO_signed_ada.pdf.

1. The Commission Should Work with the CEC to Ensure Load Forecast Accuracy and Establish a Process for Load Forecasting That Recognizes the Uncertainty of Certain Large Loads

The Commission should coordinate with the CEC to develop a workshop process aimed at ensuring load forecast accuracy at the hourly level by LSE given the increasing impacts of electrification, large loads, load shifting, DERs, and DR. The 2024 Integrated Energy Policy Report (IEPR) load forecast shows significant load growth over the coming five and ten-year horizons, as depicted in Figure 1 below. In only five years, the CEC forecasts more load growth than occurred over the past 33 years (1990 to 2023).[8] Forecasted load growth well outside of the historical pattern is likely to be highly uncertain and variable.

Figure 1 - CEC 2024 IEPR Load Forecast Aggregate for PG&E, SCE, and SDG&E areas

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Retail Sales (TWh/yr)	199.9	205.1	212.6	225.7	237.7	249.8	261.6	271.3	282.1	293.0
Percent Change from 2025	0%	3%	6%	13%	19%	25%	31%	36%	41%	47%

While the IEPR has been long established as the forecast for system RA purposes, that process has been a single year forward.[9] With the RCPPP now considering multi-year forward obligations for new and existing resources, it is critically important that the load forecast be as accurate as possible and account for the inherent speculative nature of data center load. Failing to do so will result in costly procurement above need if the forecast is too high, and constrained deadlines to meet needs if it is too low.

To bring reliable, clean, and affordable service to Californians, the Commission should work closely with the CEC and stakeholders to ensure a viable process to accurately forecast

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[8] CEC Energy Consumption Data files contain information going back to 1990 which indicate the change in consumption between 1990 and 2023 (the last date of recorded data) was only 21 percent: https://www.energy.ca.gov/files/energy-consumption-data-files.

[9] While the RA program has moved to a three-year forward requirement for local RA, the amount of local RA need is determined by the CAISO and is influenced as much by transmission constraints as it is by load changes.

load up to a ten-year horizon and to do so at an hourly granularity by LSE. This is consistent with the OIR guidance stating, "[t]his proceeding will be the primary venue for ongoing Commission-CAISO-CEC MOU coordination with the CEC's IEPR process."[10]

To this end, the Commission should coordinate with the CEC to hold a workshop(s) to ensure that the IEPR load forecast process and its use for CPUC IRP purposes provides an accurate and timely load forecast. This process should aim to identify all sources of data that will enable highly accurate load forecasting, providing the maximum amount of time for LSEs to adjust procurement to the accurate forecast.

For example, the Demand Analysis Working Group (DAWG) met at the CEC on July 16, 2025, to discuss several issues impacting load forecasts. Among those issues was the forecasting of data center load. These large load changes significantly affect the grid as a whole. Even more problematic, however, is that large loads can disproportionately affect an individual LSE, where a single data center could double, or even more than double, the LSE's total load in the area where it is located. Failures in accuracy and timeliness, failure to account for the onsite generation of some data centers, or failure to account for the inherent uncertainty with these loads will result in significant consequences for that LSE. Too high a forecast could result in substantial procurement costs with little or no additional load to spread those costs. With too low a forecast, the LSE could risk missing renewables portfolio standards (RPS) requirements, which are based on actual energy consumption after the fact, and an RA requirement that was too low to meet reliability needs.

PG&E and SCE presented at the DAWG meeting regarding their forecasting of data center growth. Within their presentation, PG&E stated, "[f]or multiple forecast cycles, forecasts

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[10] OIR, at 10.

will likely be highly uncertain due to the nascency of the data center technology and markets and due to the complexity of data center projects."[11] SCE presented that it had increased the likelihood of eight projects, decreased the likelihood of nineteen projects, and maintained the likelihood of sixteen projects.[12] These presentations demonstrate the uncertainty inherent in forecasting data center load that must be accounted for when asking LSEs to procure costly new resources. In addition, the Commission should require IOUs to identify how and when during the forecasting processes the IOU becomes aware of the potential for a new data center or other large loads and incorporates that information into load forecasts for the IOU, CCA or electric service provider (ESP). This is the best method to ensure that all parties can work with the Commission, the CEC, and the potential customer to provide accurate data to the load forecast process.

The Commission and CEC's approach to load forecasting and procurement planning should also establish parameters for including data center and other loads in forecasts used to determine procurement obligations, given the potentially speculative nature of these loads. Given that data center loads are uncertain and cannot be made more certain even with very careful forecasting, the approach to forecasting and directing procurement for data center load needs to be carefully crafted. The Commission should examine ways in which it can ensure a reasonable procurement program that may, in part, be based on speculative large loads such as data centers.

For example, the load forecast process should include a meaningful way for LSEs to dispute the forecast if they identify inaccurate load additions. Currently, the IEPR process is a zero-sum game. That is, to the extent one LSE changes its load forecast, the CEC adjusts other LSEs' forecasts in an equal and opposite direction. This process ensures that the total system-

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[11] *Demand Analysis Working Group Meeting* (July 16, 2025): https://www.energy.ca.gov/event/meeting/2025-07/ca-energy-demand-forecast-economic-demographic-inputs-and-data-center.

[12] *Ibid.*

wide load forecast remains unchanged. However, this may also not result in the best and most accurate estimates. The Commission and CEC should consider how best to address individual load forecast adjustments and their relationship to the system forecast as a whole.

2. The Commission, in Coordination with the CAISO, Should Reform Transmission Planning Tools and Decision-Making Processes to Account for Uncertainty and Ensure a Competitive Market

The Commission, in coordination with the CAISO, should reform its transmission planning tools and decision-making process to be more robust under uncertain scenarios. The ability for new capacity to interconnect to the transmission system is a key constraint on decarbonization efforts. Historically, the Commission has optimized the resource portfolios used in the TPP using a single set of assumptions. This process should be revisited in this proceeding to account for current uncertainty in these assumptions, given the emergence of new large loads like data centers, changes in federal policy, and new technology innovation.

The new IRP proceeding should include a specific focus on reforming tools and decision-making processes to accommodate uncertainty by: (1) including in scope a stakeholder process on specifically identifying risks and uncertainty bounds for a robust optimization[13] to inform portfolio development and transmission planning decision-making; (2) adding a "decision-making under uncertainty" approach to RESOLVE modeling and including a robust portfolio as a potential scenario for the TPP; and (3) increasing the burden of proof on model assumptions that defer in-state transmission investments. Doing so will establish an expectation that the PSP is both low cost ***and*** low risk.

It can also potentially help ease market dynamics that drive up procurement costs for LSEs. The current IRP process identifies infrastructure and portfolio needs through a single set of

[13] Robust optimization finds a solution that does well across a range of scenarios, with a focus on minimizing tail risk.

assumptions, and the CAISO only studies interconnection requests up to 150 percent of capacity from existing or planned infrastructure. As a result, generators can name their price if procurement is ordered, and they are the only ones with access to the grid. When reforming transmission planning tools and decision-making processes to be more robust under uncertain scenarios, the Commission should focus on identifying market dynamics that can create market power or drive-up costs significantly beyond what is planned and seek to minimize these conditions.

Research sponsored by Sonoma Clean Power and Peninsula Clean Energy has demonstrated the application of robust optimization.[14] Results show that more proactive approval of transmission capacity, particularly lines that enable a diverse set of resources that satisfy grid needs under a range of scenarios, are the main opportunity to improve robustness of California's grid planning. The Commission and CAISO should therefore reform transmission planning tools and decision-making processes to account for uncertainty using robust optimization methods that result in a portfolio that does well across a range of scenarios.

3. The Commission and the CAISO Should Hold a Public Stakeholder Process to Address FERC Order 1920

The Commission should coordinate with the CAISO to hold a public stakeholder process to address the requirements of FERC Order 1920. FERC Order 1920 requires the CAISO to conduct long-term planning for regional transmission facilities over a 20-year time horizon at least every five years and study three plausible scenarios stress tested for extreme weather.[15] The Commission, in its role as the state regulator tasked with shaping scenario development, should make sure all three scenarios are outputs of the IRP process that reflect the need for policy-

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14 *Joint Comments of Sonoma Clean Power Authority and Peninsula Clean Energy on the Order Instituting Rulemaking,* R.25-06-019 (Aug.1, 2025) (not yet published).

15 *FERC Order No. 1920-A Compliance Update*, Stakeholder Workshop (Mar. 13, 2025): https://www.caiso.com/documents/presentation-ferc-order-no-1920-mar-13-2025.pdf.

driven upgrades. Changes to the TPP portfolio development process resulting from FERC Order 1920 should be formalized in an update to the cross-agency MOU.[16]

4. The Commission and the CAISO Should Coordinate to Ensure Reliable Delivery of OOS Resources Under Long-Term Contract

The Commission and the CAISO should prioritize updating the process for allocating long-term maximum import capability (MIC) to LSEs to ensure reliable delivery of OOS resources. The 2025-2026 TPP base case includes a significant amount of new OOS wind capacity, beginning with 4.7 gigawatts (GW) in 2030 and increasing to 15.7 GW in 2045.[17] Currently, the CAISO only allocates long-term MIC for RA contracts active *in the next RA year*. Until the CAISO process for allocating long-term MIC changes, LSEs signing long-term power purchase agreements (PPA) for resources with online dates more than one year in advance will be unable to secure MIC for those resources until the year before the resources come online. The uncertainty around LSEs' ability to secure MIC to support reliable delivery of OOS resources complicates long-term contracting with these resources. The CAISO has committed to reconsidering the methodology for allocating long-term MIC in its RA Modeling and Program Design initiative. The Commission and CAISO should coordinate to provide certainty around the deliverability of OOS resources being procured under long-term contract.

5. The Commission Should Evaluate Renewable Curtailments with the CAISO to Ensure PSP Modeling Accurately Reflects Congestion

The Commission and the CAISO should ensure the PSP modeling accurately reflects congestion. The CAISO routinely reports on renewable energy curtailments that occur due to constraints on the transmission system. The May 31, 2025, renewable curtailment report shows

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16 MOU, *see supra* n.7.

17 D.25-02-026, *Decision Transmitting Electricity Resource Portfolios to the California Independent System Operator for 2025-2026 Transmission Planning Process*, R.20-05-003 (Feb. 20, 2025), at 19: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M557/K879/557879249.PDF.

that 2,741,671 megawatt-hours (MWh) of renewable energy have been curtailed year-to-date.[18] While this amount is not the same every day, the daily average over that period is approximately 18,250 MWhs per day. This raises two primary questions. First, is the IRP effectively addressing congestion in developing a PSP? Second, is California and the global environment better off improving the transmission system to avoid these curtailments, enabling the displacement of other emitting resources elsewhere in the West?

This proceeding should examine both questions, as they are fundamental to ensuring that Californians' needs are met and that the resources paid for by Californians provide their maximum value. This is made difficult when part of their value, GHG reduction, includes positive externalities that will be realized by those who have not paid for the resources. Addressing these critical questions will help to inform what and how much transmission should be built, considering the benefits of potential exports of California renewable resources.

6. The Commission and the CAISO Should Consider How to Adjust Long-Term Planning Processes to Ensure Reliability as Reliability Needs Shift

The Commission and the CAISO should consider whether the interactions between RESOLVE modeling and the CAISO's deliverability assessment must evolve as reliability needs shift. The current IRP planning tools, the RA program, and the CAISO's approach to grid planning and interconnection are all based on summer deliverability conditions. This approach has been logical for many years, as the CAISO system has historically been summer peaking. However, the Commission has found that managed net peak loads shift to winter as soon as

[18] *Wind and Solar Curtailment May 31, 2025*: https://www.caiso.com/documents/wind-solar-real-time-dispatch-curtailment-report-may-31-2025.pdf.

2040.[19] The RESOLVE model will not select capacity that is not deliverable during the *current* peak. For example, while NP 15 congestion occurs in the south to north direction in most hours, deliverability could be unavailable in northern California due to north to south constraints during the summer peak, and RESOLVE would not map resources in northern California.

Ignoring resources' ability to deliver during *future* critical periods could introduce unnecessary barriers to adding clean capacity to prepare for future reliability needs. The Commission and the CAISO should therefore work together in this proceeding to evaluate whether the IRP's long-term planning process needs to evolve to consider resources' ability to reliably deliver during non-summer periods, and whether the RA and deliverability processes need to also evolve to support these changes.[20]

B. A Standing Track in the IRP Proceeding Should be Established to Examine the Large IOUs' BPPs

The Commission should adopt a standing scoping item within the IRP proceeding to examine whether the large IOUs' BPPs and applicable procurement rules should be revised. The OIR states:

> This proceeding will also be, to the extent necessary, the venue for considering the bundled procurement plans and procurement rules applicable to the three large electric investor-owned utilities, including activities associated with Public Utilities Code Section 454.5 and other related issues pursuant to Assembly Bill 57 (Stats.2002, Ch.850, Sec. 3), which returned utilities to full procurement responsibilities (*see* Decision 04-01-050). An update

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19 *Administrative Law Judge's Ruling Seeking Comments on Electricity Resource Portfolios for 2025-2026 Transmission Planning Process*, R.20-05-003 (Sept. 12, 2025) at 4: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M539/K999/539999211.PDF.

20 Examples of potential changes include developing a non-summer deliverability measurement, similar to the CAISO's off-peak deliverability measurement, that is used for RA in non-summer months, or, as CalCCA proposed in R.23-10-011, allowing co-located energy-only resources to contribute RA when it and its paired storage do not exceed deliverability limits in aggregate under slice-of-day. *See California Community Choice Association's Proposals On Track 3*, R.23-10-011 (Jan. 17, 2025), at 20-25: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M553/K679/553679242.PDF.

> to these procurement policies and processes may be necessary, and, to the extent relevant, activities will be coordinated with the current rulemaking associated with the power charge indifference adjustment (R.25-02-005).[21]

Historically, the Commission reviewed the large IOUs' BPPs in the Long-Term Planning Proceeding (LTPP). The IOUs current BPPs were last approved, with modifications, by D.15-10-031 in October 2015.[22] Since then, the IOUs have updated various sections of their BPPs through advice letters as needed. Since the Commission transitioned from LTPP to IRP, the large IOUs' BPPs have not been holistically reviewed in nearly ten years. The Commission has recognized that the BPPs have been a consistent problem in the Energy Resource Recovery Account (ERRA) compliance proceedings with no venue in which to address them.[23] The Commission should therefore establish a standing track in the IRP proceeding to examine the large IOUs' BPPs and determine whether they should be revised.

In its initial review, the Commission should evaluate the IOUs' BPPs to ensure timely portfolio optimization and to make clear the standard for the IOUs' procurement and sales activities. For example, in Pacific Gas and Electric Company's (PG&E) 2019 ERRA Compliance proceeding, Application (A.) 20-02-009, parties disputed whether PG&E's BPP and its testimony in the ERRA Compliance proceeding were insufficiently transparent to demonstrate how PG&E determined its RA positions, what those positions were at the time of PG&E's solicitations, and

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21 OIR, at 2.

22 *See* D.15-10-031, *Decision Approving 2014 Bundled Procurement Plans,* R.13-12-010 (Oct. 23, 2015).

23 *Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes*, R.25-02-005 (Feb. 26, 2025), at 24 (stating that "[i]ssues regarding sufficiency of BPPs have been repeatedly raised in individual ERRA proceedings, focusing on questions about whether IOU management of procurement activities is reasonable and compliant with Commission rules.").

whether the operational constraints in the BPP had been updated between solicitations.[24] In PG&E's 2022 ERRA Compliance proceeding, A.23-02-018, CalCCA argued PG&E did not make reasonable attempts to sell nearly one gigawatt of excess RA capacity to other LSEs before counting that capacity towards its own system reliability incremental procurement targets. [25]

In San Diego Gas and Electric Company's (SDG&E's) 2022 ERRA Compliance proceeding, A.23-06-002, the CCA Parties argued how SDG&E's BPP is too vague regarding sales of Excess RA, and contains no real requirements or guidelines for maximizing RA sales to benefit customers,[26] providing SDG&E with too much leeway to sell or withhold RA from the market based on its discretion.[27] In all three cases, the CCAs have argued part of the remedy to these short-comings is changes to the BPPs.

These disputes make clear that a venue is needed to consider changes to the existing BPPs as the RA market has evolved. For these reasons, the Commission should establish a standing scope item within the IRP proceeding to review the large IOUs' BPPs and commit to

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[24] *See* A.20-02-009, Ex. CCA-01, *Prepared Direct Testimony of Brian Dickman on behalf of the Joint Community Choice Aggregators*, at 45-55 (July 10, 2020). D.21-07-013 adopted a settlement agreement resolving that dispute in which PG&E and the Joint CCAs would "engage in discussions about Resource Adequacy solicitations" and "PG&E also agrees to propose revisions to Appendix S in the future if it is appropriate." D.21-07-013, *Decision Resolving Phase One of Pacific Gas and Electric Company's ERRA Compliance Application for the 2019 Record Year* (July 16, 2021), at 7-8, 11, and Conclusions of Law (COL) 2-7.

[25] *California Community Choice Association's Opening Brief*, A.23-02-018 (Oct. 4, 2024), at 10-23. The remedy sought in that case is for the Commission to revisit PG&E's BPP in the IRP proceeding to ensure PG&E is making excess RA available to the market in a timely and comprehensive manner, including through scheduled solicitations and market offers outside the scheduled solicitation process. CalCCA sought the IRP as the right venue because this OIR had not yet been opened.

[26] A.23-06-002, Exh. CCA-01 at 15:16-17, Attachment D, and Exh. CCA-02 at SDG&E Response to SDCP/CEA DR 3.10.

[27] A.23-06-002, Ex. CCA-02 at SDG&E Response to SDCP/CEA DR 3.01 (stating SDG&E withholds RA from solicitations for far more reasons than those identified in the BPP, including unidentified "other considerations."). Here again, the CCAs ask for the Commission to consider changes to the BPP in the IRP. *See*, *Opening Brief of San Diego Community Power and Clean Energy Alliance* A.23-06-002 (Apr. 12, 2024), at 13-15. The CCAs sought the IRP as the right venue because this OIR had not yet been opened.

evaluating them to ensure timely portfolio optimization and to make clear the standard for the IOUs' procurement and sales activities in its initial review.

C. The Commission Should Evaluate How to Reliably Serve Load with a Reduced Reliance on Gas Resources in the Most Cost-Effective Manner

1. The Commission Should Evaluate How to Reduce Reliance on Gas Resources Currently Needed to Serve Load in Local Areas

CalCCA agrees with the Commission when it states, "[t]here is further work to be done focusing specifically on transmission facilities needed to interconnect resources, reliably serve load centers, and reduce dependence on fossil-fueled generation resources in local areas."[28] Local reliability needs are responsible for retention of some of the most polluting generation in the state, undermining the state's decarbonization and environmental justice goals. The amount of generation that must be physically located within a locally constrained area is highly dependent on the transmission available to transmit energy from resources outside the local area. If transmission capacity is limited, resources in the local area are needed to maintain reliability. Today, such resources are often emitting resources.

Local RA requirements can decline if new transmission is built that allows resources outside the local area to be delivered to local area load. Therefore, there are two ways to address local reliability, either by: (1) having sufficient generation physically located within the local area; or (2) having sufficient transmission build to relieve the local area constraints and allow generation outside the local area to be delivered to load within the local area. Addressing local reliability needs is a complex problem requiring coordination between CAISO and the Commission to ensure the most cost effective and efficient solution to this serious issue.

[28] OIR, at 13.

The Commission and the CAISO should develop a process to evaluate transmission and non-transmission alternatives to determine which alternatives are more cost-effective and feasible given existing land use constraints. This evaluation will provide the Commission with the information it needs to move forward with meaningful steps, either through increased gas retirements in the base case transmission planning portfolios or through planning for local resource development, towards reducing the operation of existing gas resources. The Commission should not delay this topic to later IRP cycles, as it has already been deferred for many years.

2. The Aliso Canyon Constraint Should Be Embedded in Models Used to Develop the PSP Portfolios

The Commission should embed the Aliso Canyon constraint into models used to develop the PSP portfolio. D.24-12-076, which finds Aliso Canyon necessary for natural gas and electric reliability and cost containment, appropriately directs resource planning and procurement decisions to the IRP proceeding:

> [O]ther proceedings are appropriate for planning and procurement of electricity resources. As noted by CalCCA, procurement is already occurring in other proceedings that may in part address the need for Aliso Canyon. We agree with CalCCA that procurement in those proceedings ensures that the mix of resources is effective and efficient and considered as a whole. Proceedings that may consider procurement of resources that address the services currently provided by Aliso Canyon include IRP (R.20-05-003 or its successor proceeding)…[29]

The Commission's approach taken in D.24-12-076 places the role of electric resource planning and procurement in a consolidated proceeding, the IRP proceeding, where the Commission can ensure consistent planning using all information about grid needs. Embedding the Aliso Canyon constraint into the PSP portfolio will ensure that the planned resource mix, and

[29] D.24-12-076, *Decision Adopting Biennial Assessment Process*, Investigation 17-02-002 (Dec. 19, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K009/551009286.PDF.

transmission to support that resource mix, address grid needs currently met by Aliso Canyon. This approach is the best way to ensure that electricity remains as affordable as possible while meeting reliability and policy needs. For these reasons, the Commission should embed the Aliso Canyon constraint into the model used to develop the PSP portfolio.

D. The OIR's "Coordination with DWR on LLT Resource Procurement" Scope Item Should be Updated to Include the Establishment of a Procurement Group and Details of Cost-Benefit Allocation

The Commission should include the establishment of a procurement group and development of cost-benefit allocation into the scope of the DWR LLT resource procurement scope item. DWR may embark on a potentially significant amount of procurement on behalf of all Commission-jurisdictional LSEs. The OIR states:

> This proceeding will be the venue for the Commission to consider any proposed contracts for LLT resources by DWR. In addition, prior to DWR conducting solicitations, it may be necessary for the Commission to work with DWR on administrative issues associated with DWR's work. If that is necessary, this proceeding will also be the venue for any necessary coordination or decision-making. Further, possible future analyses related to the initial need determination findings in D.24-08-064 for centralized procurement of LLT resources will also take place in this new proceeding.[30]

There are two items that must be addressed in this OIR to make the DWR central procurement effective and efficient. First, this proceeding should form a procurement group so that parties can prepare the best representatives for participation in the review of potential DWR procurement. D.24-08-064 requires that, "DWR convene a procurement group that includes representatives from, but not necessarily limited to, non-market participants, Tribal Nations, community groups, other state agencies, and LSEs."[31] The structure of included representatives

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[30] OIR, at 16.

[31] D.24-08-064, *Decision Determining Need for Centralized Procurement of Long Lead-Time Resources*, R.20-05-003 (Aug. 24, 2022), at 5: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M539/K202/539202613.PDF.

is different than those in the current IOU procurement review groups (PRG) or cost allocation mechanism (CAM) PRGs. Given these differences, the Commission should use this OIR to develop the PRG for DWR procurement to provide clarity on who can participate and how participation will occur.[32]

Second, this OIR should define the structure for how costs and benefits of DWR procurement will be allocated. D.24-08-064 states, "[f]urther details on the allocation of costs and benefits of procurement conducted as a result of this decision will be determined in this proceeding or its successor."[33] This element is important to LSEs as they pursue their own procurement to fully understand the cost impacts of DWR procurement to their customers.

E. The Commission Should Develop a More Structured Waiver Process for MTR Obligations

The Commission should include in the scope of this proceeding a process to develop a more structured waiver process for MTR obligations. The OIR includes "Ongoing Monitoring, Compliance, and Enforcement of Prior Procurement Orders" in the scope of this proceeding.[34] As part of this scope:

> Commission staff are conducting ongoing analysis of the compliance filings to determine LSEs' progress and compliance toward the procurement requirements. To the extent that LSEs are found deficient in any of their procurement, compliance and enforcement work will take place in this proceeding.[35]

D.21-06-035 (MTR Order) provides direction on how the Commission should enforce compliance with LSE MTR obligations. It directs the Commission to assess penalties based on

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32 *Id.* at 64: "DWR preparatory activities, including formation of procurement group – late 2024 and 2025" and "DWR development of solicitation plans and materials, in consultation with Commission staff and procurement group."

33 *Id.* at 4.

34 OIR, at 14.

35 *Id.* at 14-15.

its Resolution M-4846[36] and consideration of "good faith efforts."[37] Resolution M-4846 adopts a penalty assessment methodology which establishes factors that "shall be used in setting penalties that are appropriate to a violation," including but not limited to: (1) severity or gravity of the offense (*e.g.,* number of violations); (2) conduct of the regulated entity (*e.g.,* actions taken to prevent a violation and prior history of violations); and (3) totality of circumstances in furtherance of the public interest (*e.g.,* ensuring that a regulated entity does not have incentives to make economic choices that cause or unduly risk a violation).

While the MTR Order and Resolution M-4846 provide guidance, they do not establish a structured process for LSEs to request a waiver of penalties, including the requirements for demonstrating good faith efforts, and for the Commission to evaluate these demonstrations in its assessment of penalties. As Commission staff is in the process of analyzing LSE procurement progress for compliance, it is necessary for the Commission to provide LSEs with clear expectations on the penalty assessment process if an LSE is found non-compliant despite good faith efforts. The Commission should therefore develop a structured waiver process for LSEs to demonstrate good faith efforts for Commission consideration when assessing penalties as part of this proceeding.

III. SCHEDULE RECOMMENDATIONS

CalCCA recommends that the OIR's proposed schedule be modified to: (1) allow sufficient time for LSEs to develop their individual plans following the release of the inputs and assumptions (I&As) and compliance guidance; (2) establish the schedule and cadence of LSE

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[36] Resolution M-4846, *Resolution Adopting Commission Enforcement Policy* (Nov. 5, 2020) (Resolution M-4846).

[37] D.21-06-035, *Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026)*, R.20-05-003 (June 24, 2021), COL 27: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF.

procurement compliance filings when developing the RCPPP; and (3) use this proceeding to develop the reliability and GHG-reduction RCPPP frameworks in two tracks.

A. Individual LSE IRP Plans Should be Due No Earlier than February 2026, but No Sooner than Six Months After the I&A and Compliance Guidelines are Issued

The Commission should require the filing of individual LSE IRP plans no earlier than February 2026, but no sooner than six months after the I&A and compliance guidelines are issued by Energy Division staff. The OIR states:

> According to the schedule in R.20-05-003, Commission staff were due to issue these updated filing requirements by May 1, 2025, but this work is behind schedule. Thus, this OIR will modify the schedule for the individual IRP filings by each LSE in this proceeding. The individual IRPs will be required no earlier than December 1, 2025 and potentially later.[38]

CalCCA appreciates the Commission's recognition that delayed filing requirements necessitate a modification of the schedule for individual LSE IRP filings. LSEs put significant time and effort into their individual IRPs, including substantial modeling work that cannot meaningfully begin until data I&As are finalized. Because individual LSE plans are dependent on the I&As and compliance guidelines provided by Energy Division Staff, the Commission should establish a standard that individual LSE IRPs are due no earlier than six months after the issuance of these documents. If the Commission declines to adopt this recommendation, it should, at minimum extend the December 1, 2025, deadline by ten days to Thursday, December 11, 2025, to accommodate the Thanksgiving holiday.

If the delayed filing requirements and resulting delay in individual LSE plan filings impact the 2026-2027 TPP portfolio development timeline, the Commission should allow LSEs an opportunity to submit their "under contract" resources to Energy Division in advance of filing

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[38] OIR, at 11.

their updated individual LSE IRP plans. This will allow the Commission to incorporate these contracts into the 2026-27 TPP portfolio. I&As will likely have changed considerably since 2022 IRP filings, making the 2022 IRPs out of date. To mitigate the potential adverse consequence of delaying IRP filings (*i.e.,* that the Commission will continue to use 2022 IRP data to inform LSE procurement planning used to develop the portfolios), the Commission should allow LSEs to submit their most recent contract data and account for that data in developing the portfolios.

B. The Commission Should Establish the Schedule and Cadence of LSE Procurement Compliance Filings When Developing RCPPP, Rather than Within the OIR

The schedule and cadence of future LSE procurement compliance filings should be determined when developing the RCPPP, rather than within this OIR. The preliminary schedule in the OIR states that LSE procurement compliance filings will occur on December 1, 2025, and June 1, 2026, <u>*and every December 1 and June 1 thereafter*</u>.[39] This appears to presuppose when compliance filings will occur under RCPPP before the RCPPP has been developed. The Commission and parties are currently evaluating the filing cadence. Energy Division Staff's RCPPP proposal asks parties how often compliance filings should occur,[40] and parties provide a range of recommendations including once per year, twice per year, aligned with the RA compliance timing, or only in years not including an IRP filing.[41] Some parties also recommend consolidating filing templates across the IRP, RA, and RPS compliance programs.[42] The

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39 *See* OIR, at 18 (emphasis added).

40 *Administrative Law Judge's Ruling Seeking Comments On Reliable and Clean Power Procurement Program Staff Proposal*, *Attachment A: Staff Proposal: Reliable and Clean Power Procurement Program*, R.20-05-003 (Apr. 29, 2025), at 52-53: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M565/K140/565140169.PDF.

41 *See, e.g., Peninsula Clean Energy Authority Comments on the Renewable Clean Power Procurement Program*, R.20-05-003 (July 15, 2025), at 8-9: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M574/K351/574351046.PDF.

42 *Ibid.*

Commission should therefore modify the schedule to indicate the cadence and timing of LSE procurement compliance filings under RCPPP will not be determined until the RCPPP framework has been developed.

C. The Commission Should Use this Proceeding to Develop the Reliability and GHG-Reduction RCPPP Frameworks in Two Tracks

The Commission should establish two tracks within this proceeding to develop the reliability and GHG-reduction RCPPP frameworks. The OIR states a decision may be issued in R.20-05-003 that adopts an initial framework for the RCPPP. If a framework decision is adopted, any further decision making, record development, and implementation will take place in this proceeding, R.25-06-019.[43] Following the decision in R.20-05-003 adopting an initial framework, the Commission should develop the RCPPP reliability and GHG-reduction frameworks on two tracks to thoroughly vet each framework, as recommended in CalCCA's Opening Comments on the RCPPP Staff Proposal.[44] The first track should develop the reliability framework, targeting implementation in 2029. The second track should develop the CES proposal, which needs additional work to develop the details, targeting implementation for a 2031-2033 compliance period. This will allow the CES to take effect following the 2028-2030 RPS compliance period.

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43 *See* OIR, at 14.

44 *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (July 15, 2025), at 4-6: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M573/K513/573513376.PDF.

IV. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and respectfully requests adoption of the recommendations proposed herein.

Respectfully submitted,

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

August 1, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON RELIABLE AND CLEAN POWER PROCUREMENT PROGRAM STAFF PROPOSAL

Leanne Bober,
Director of Regulatory Affairs and
Deputy General Counsel
Lauren Carr,
Senior Manager, Regulatory Affairs and
Market Policy
Eric Little,
Director of Market Design

CALIFORNIA COMMUNITY CHOICE
ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

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SUMMARY OF RECOMMENDATIONS[1]

- Reject party recommendations for near-term procurement orders that fail to consider the practical realities of the current procurement environment and overly prescriptive RCPPP frameworks that would establish LLT-specific procurement requirements, enforce procurement of the PSP, or establish excessively high procurement requirements in years T+2 through T+4;
- Adopt a new plus existing SOD-based reliability framework coupled with a CES to allow LSEs to best optimize their portfolios and address both reliability and clean energy needs in an affordable manner;
- Adopt a SOD methodology for RCPPP as recommended by numerous parties given the uncertainty and misalignment created by mELCC even if mELCC values are bounded;
- Adopt party recommendations to plan for a 0.1 LOLE reliability target rather than a buffer or CCR;
- Adopt a penalty structure for reliability requirements that differentiates between RA and RCPPP penalties, as recommended by SVCE;
- Establish a process for evaluating resource and transmission solutions to reliably serve local area load in the most cost-effective manner before adopting party recommendations for local procurement requirements in RCPPP;
- Ensure that the risks of central procurement not materializing are not borne by individual LSEs, for the reasons stated by PG&E and Shell; and
- Defer party recommendations related to the PCIA to R.25-02-005.

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

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California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to the *Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*[3] (Ruling), dated April 29, 2025, and the May 14, 2025, *Email Ruling Granting Request for Extension of Time*,[4] extending the time for comments and reply comments in response to the RCPPP Ruling.

I. INTRODUCTION

Energy Division Staff's stated goal of the Reliable and Clean Power Procurement Program (RCPPP) is to "give [load-serving entities (LSE)] a more predictable regulatory framework to procure their share of the resources needed to meet electric system reliability and

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

[3] *Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, Rulemaking (R.) 20-05-003 (Apr. 29, 2025): https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=565140721.

[4] *Email Ruling Granting Request for Extension of Time*, R.20-05-003 (May 14, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M566/K327/566327214.PDF.

greenhouse gas (GHG) emission reduction goals at least cost."[5] This goal is largely supported by parties, including CalCCA, as a way to transition away from the ad hoc procurement order process, which can result in an unpredictable, rushed, and costly procurement environment.

Despite this widely accepted goal, several parties' Opening Comments[6] and Proposals[7] advance recommendations that ignore the realities of the current procurement environment and if adopted would exacerbate the state's ongoing affordability crisis. In developing the RCPPP, the California Public Utilities Commission (Commission) should consider these realities, including the impacts that interconnection delays, federal policy, and supply chain issues have on resource availability. The Commission should also seek to co-optimize reliability and GHG-reduction frameworks by aligning these frameworks with existing compliance programs, including the Renewables Portfolio Standard (RPS) and Resource Adequacy (RA) programs, to allow these requirements to be met in the most cost-effective manner.

Many parties agree that the Commission should plan for an industry-accepted reliability standard and incentivize compliance through a robust penalty framework, rather than rely on generic procurement buffers that can result in over-procurement. Parties also agree that the Commission should establish a process for reliably serving local area load with reduced reliance on emitting resources. To implement party recommendations on local area reliability, the Commission should first evaluate how to determine which transmission and non-transmission alternatives are cost-effective and feasible before incorporating a local procurement component into RCPPP. Several parties also highlight the significant impact central procurement entity

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5 *Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, Attachment A, R.20-05-003 (Apr. 29, 2025) (Staff Proposal), at 1: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M565/K140/565140169.PDF.

6 References to parties' Opening Comments refer to those Comments submitted on or about July 15, 2025, in R.20-05-003.

7 References to parties' Proposals refer to those submitted on or about July 15, 2025, in R.20-05-003.

(CPE) procurement will have on LSE procurement. These parties emphasize the importance of ensuring that the risks of central procurement not materializing are not borne by individual LSEs that do not have control over the timing or amount of procurement.

In response to party Opening Comments and Proposals, CalCCA recommends that the Commission:

- Reject party recommendations for near-term procurement orders that fail to consider the practical realities of the current procurement environment and overly prescriptive RCPPP frameworks that would establish long-lead time (LLT)-specific procurement requirements, enforce procurement of the Preferred System Plan (PSP), or establish excessively high procurement requirements in years T+2 through T+4 and beyond;

- Adopt a new plus existing slice-of-day (SOD)-based reliability framework coupled with a clean energy standard (CES) to allow LSEs to best optimize their portfolios and address both reliability and clean energy needs in an affordable manner;

- Adopt a SOD methodology for RCPPP as recommended by numerous parties given the uncertainty and misalignment created by marginal effective load carrying capability (mELCC), even if mELCC values are bounded;

- Adopt party recommendations to plan for a 0.1 loss-of-load expectation (LOLE) reliability target rather than a buffer or collective capacity reserve (CCR);

- Adopt a penalty structure for reliability requirements that differentiates between RA and RCPPP penalties, as recommended by Silicon Valley Clean Energy (SVCE);

- Establish a process for evaluating resource and transmission solutions to reliably serve local area load in the most cost-effective manner before adopting party recommendations for local procurement requirements in RCPPP;

- Ensure that the risks of central procurement not materializing are not borne by individual LSEs, for the reasons stated by Pacific Gas and Electric Company (PG&E) and Shell Energy North America (US), L.P. (Shell); and

- Defer party recommendations related to the Power Charge Indifference Adjustment (PCIA) to R.25-02-005.

II. THE COMMISSION SHOULD REJECT RECOMMENDATIONS THAT FAIL TO CONSIDER THE PRACTICAL REALITIES OF THE CURRENT PROCUREMENT ENVIRONMENT

Party recommendations for near-term procurement orders or RCPPP designs that do not consider the practical realities of the current procurement environment should be rejected to ensure reliability and GHG-reduction procurement efforts do not result in excessive costs to ratepayers. A significant amount of procurement must occur between now and 2045 to reliably meet state policy goals.[8] This procurement must occur while managing barriers to bringing new supply online quickly and affordably, including supply chain issues, permitting challenges, interconnection delays, and federal policy changes. All of these barriers continue to create a challenging and unpredictable procurement environment.

As set forth below, the Commission should consider the availability of projects and timing of new resource development when establishing any future procurement directives, whether it be a near term procurement order or RCPPP design. As stated by Shell, "[i]t does California's ratepayers little good to set procurement targets that are unachievable given the lack of sufficient resources, or to penalize LSEs for procurement directives that are unattainable due to challenges associated with development timelines."[9] The Commission must also ensure that it bases any near-term procurement order or long-term RCPPP design on thorough needs assessments and make load forecasting improvements a priority. Finally, the Commission should

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8 Roughly 7,000 megawatts (MW) of new resources must interconnect every year in California between now and 2045 to meet the necessary level of build as set forth in Senate Bill 100 (SB 100) (De León, Chapter 312, Statutes of 2018).The *2021 SB 100 Joint Agency Report* finds a build out of roughly 175,000 MW is needed between 2021 and 2045 to meet SB 100 targets. 175,000 MW built over 24 years amounts to roughly 7,000 MW per year. 2021 SB 100 Joint Agency Report (Mar. 2021) at 10: https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349.

9 Shell Opening Comments, at 6.

also avoid overly prescriptive requirements that inhibit LSEs' ability to manage uncertainty and navigate constraints in an affordable manner.

A. Party Recommendations for Near-Term Procurement Orders Should be Rejected

The Commission should reject party recommendations for near-term procurement orders given there is: (1) insufficient record to demonstrate need; (2) significant uncertainty in the load forecast that requires additional consideration; and (3) resource development bottlenecks that could be exacerbated by additional procurement orders. The Commission must ensure that before any near-term procurement is ordered, it is informed by a robust needs assessment, based on a load forecast that accounts for the significant uncertainty of electrification and large loads, and feasible given resource development timelines.

1. Any Interim Procurement Order Must Be Supported by a Needs Assessment That Is Thoroughly Vetted by the Commission and Parties

Party recommendations for a near-term procurement order are premature given a needs assessment has not been completed and forecasted load increases are highly uncertain. American Clean Power – California (ACP-CA), Solar Energy Industries Association (SEIA), Large-Scale Solar Association (LSA), and Independent Energy Producers Association (IEP) (collectively, the Joint Parties), PG&E, and San Diego Gas & Electric Company (SDG&E) each recommend near-term procurement orders based upon different interpretations of need. The Joint Parties recommend the Commission initiate a near-term needs order for 2028-2032 by September 2025 based upon a "low-end estimate" of the reliability gap driven by load forecast increases.[10] PG&E recommends a procurement order to meet a need of roughly 2,900 MW of net qualifying capacity (NQC) to address an expected energy storage charging capacity shortfall.[11] SDG&E

[10] Joint Parties Proposal, at 3.
[11] PG&E Opening Comments, at 7.

recommends "that the Commission require LSEs to procure by 2030 a minimum of 25 [percent] of the clean energy resource need for 2030 that is reflected in their 2022 IRP, while accounting for any resource additions ([mid-term reliability (MTR)] and supplemental MTR) that have come online since the last IRP."[12] While all of these parties recommend different levels of procurement, they also all fail to provide a clear determination of need.

The Commission must ensure that before any near-term procurement is ordered, it is informed by a thoroughly vetted needs assessment. CalCCA supports party recommendations that recognize the requirement for a needs assessment and identification ***before*** ordering procurement. For example, the California Independent System Operator (CAISO) states:

> [a] first track dedicated to a near term needs assessment for the 2028- 2032 timeframe and potential new procurement order to be issued as soon as the end of 2025 *if needs are identified*, and a second track on a longer timeline focused on continued development of a comprehensive RCPPP framework. Establishing a track dedicated to a near-term needs assessment will allow parties to focus on *developing and vetting Commission and party analyses of resource sufficiency* in 2028-2032 to support a potential new procurement order as soon as the end of 2025.[13]

A needs assessment in advance of a procurement order is especially critical at this time, given the significant uncertainty in the current load forecast due to electrification and data center load and market dynamics affecting resource development as described below. In addition, LSEs' individual IRPs have not been updated since 2022, and could change significantly in 2025 due to updated inputs and assumptions, resource cost, technology availability, and other factors. Therefore, these outdated IRPs should not be used as the basis of a procurement order.

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12 SDG&E Opening Comments, at 11.

13 CAISO Opening Comments, at 3 (emphasis added).

2. The Commission Should Work with the CEC to Assess the High Degree of Variability in Data Center Growth Before Basing a Procurement Order on Speculative Load

Data center impacts on the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) load forecast require further consideration before ordering procurement. The Joint Parties base their recommendation for a procurement order on the IEPR load forecast, "which includes approximately 5 gigawatts (GW) of additional peak load by 2032 (4 GW by 2030) relative to the prior, 2023 IEPR forecast."[14] ACP-CA states, "[w]hile the magnitude of this load growth is somewhat uncertain, its existence and general trajectory are clear – as are the resources needs it will entail."[15] CalCCA disagrees that the load forecast's impact on the resource need is clear. Forecasted load growth in the IEPR is higher than history supports and is uncertain. For example, the 2024 IEPR projects load growth between 13 percent and 36 percent in the 2028–2032 period, as shown in Figure 1.[16] Historically, it has taken decades to realize similar levels of growth. A 13 percent increase in load took 26 years (1997–2023) to materialize, and a 36 percent increase has not occurred in the historical record reviewed.[17]

Figure 1: CEC 2024 IEPR Load Forecast Aggregate for PG&E, SCE, and SDG&E Areas

Figure 1 - CEC 2024 IEPR Load Forecast Aggregate for PG&E, SCE, and SDG&E areas

Year	2025	2026	2027	2028	2029	2030	2031	2032
Retail Sales (TWh/yr)	199.9	205.1	212.6	225.7	237.7	249.8	261.6	271.3
Percent Change from 2025	0%	3%	6%	13%	19%	25%	31%	36%

The level of load growth depicted in the 2024 IEPR is unprecedented in recent history and is primarily driven by anticipated load growth due to data centers. However, this data center load growth is uncertain. At the July 16, 2025, CEC Demand Analysis Working Group meeting

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14 Joint Parties Proposal, at 4.
15 ACP-CA Opening Comments, at 3.
16 CEC 2024 IEPR Baseline forecast aggregated for PG&E, SCE, and SDG&E areas.
17 CEC Energy Consumption Data files contain information going back to 1990 which indicate the change in consumption between 1990 and 2023 (the last date or recorded data) was only 21 percent. https://www.energy.ca.gov/files/energy-consumption-data-files.

at the CEC, PG&E stated, "[f]or multiple forecast cycles, forecasts will likely be highly uncertain due to the nascency of the data center technology [and] markets and due to the complexity of data center projects." [18] At the same meeting, Southern California Edison Company (SCE) presented that they had increased the likelihood of eight projects, decreased the likelihood of nineteen projects, and maintained the likelihood of sixteen projects.[19]

The high degree of variability in data center growth deserves a more complete dialogue and evaluation before using the current IEPR load forecast as a basis for ordering any interim procurement. The Commission should, therefore, focus its efforts on: (1) coordinating with the CEC to develop a workshop process aimed at ensuring load forecast accuracy at the hourly level by LSE given the increasing impacts of large loads; (2) requiring the investor-owned utilities (IOU) to identify how and when during the forecasting processes each IOU becomes aware of the potential for a new data center or other large loads and incorporates that information into load forecasts for the IOU, CCA, or electric service provider (ESP); and (3) establishing parameters for including data center and other large loads in forecasts used to determine procurement obligations, given the potentially speculative nature of these loads.

Given that data center loads are uncertain and may not be able to be made more certain even with very careful forecasting, the approach to forecasting and directing procurement for data center load needs to be carefully crafted. The Commission should examine how it can ensure a reasonable procurement program that may, in part, be based on speculative large loads such as data centers.

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[18] July 16, 2025, CEC Demand Analysis Working Group Meeting: https://www.energy.ca.gov/event/meeting/2025-07/ca-energy-demand-forecast-economic-demographic-inputs-and-data-center.

[19] *Ibid.*

3. The Commission Should Ensure That Any Future Procurement Orders and RCPPP Design are Feasible Given Resource Development Timelines and Prioritize Reducing Bottlenecks

The Commission should ensure any future procurement orders, and the RCPPP design, are feasible given challenges associated with development timelines. The Commission should also seek to reduce bottlenecks that prevent contracted resources from coming online and interconnecting in a timely manner. The Utility Reform Network (TURN) recommends that the Commission take:

> all possible measures to lock in pre-sunset pricing for new wind and solar projects," by issuing "an immediate interim procurement order directing all [LSEs] to contract for wind and solar generation expected to be eligible for the relevant federal tax credits due to their ability to commence (or complete) construction by the relevant deadlines in [the One Big Beautiful Bill].[20]

The Commission should reject this recommendation because introducing a rapid increase in demand while LSEs are already in the process of procuring to meet MTR requirements and LSE-specific clean energy goals could result in dramatic price increases. In addition, many factors could prevent resources from obtaining investment tax credits (ITC) and production tax credits (PTC), even if LSEs contract for these projects as soon as possible. For example, Federal guidance issued will likely slow the progress of renewable generation not already underway, jeopardizing the ability to meet H.R. 1 deadlines.[21] In addition, issues of supply chain,

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[20] TURN Opening Comments, at 2.

[21] In addition to H.R. 1, there is Federal guidance that requires, "all decisions, actions, consultations, and other undertakings—including but not limited to the following—related to wind and solar energy facilities shall require submission to the Office of the Executive secretariat and Regulatory Affairs, subsequent review by the Office of the Deputy Secretary, and final review by the Office of the Secretary." This is followed by a list of 69 items that must be reviewed. *See* Department of the Interior Memorandum (July 15, 2025): https://www.doi.gov/media/document/departmental-review-procedures-decisions-actions-consultations-and-other.

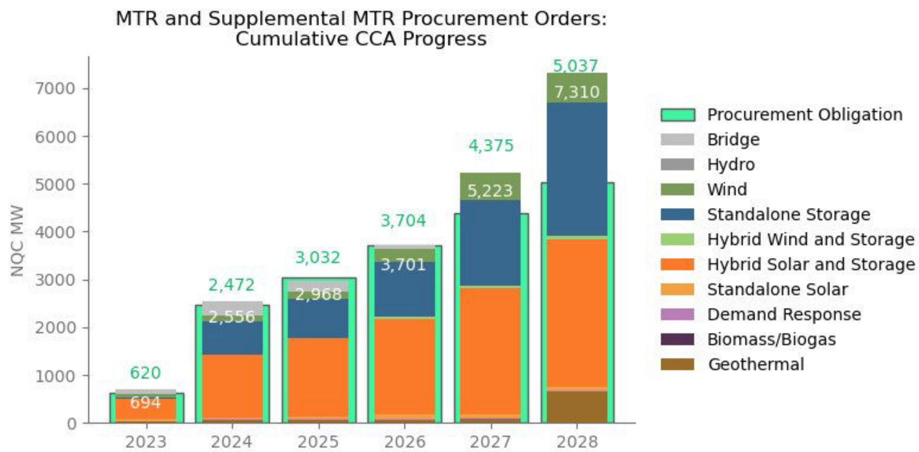
interconnection upgrade delays, and permitting difficulties have been well documented throughout the MTR process.

These problems are not solved by additional procurement orders that push even more demand into an already constrained market. Doing so will not make the components more available; the interconnection upgrades completed sooner or expedite the permitting process. Any of these individually is a significant threat to meeting the timeline specified in H.R. 1, and taken together, cast serious doubt on the ability of LSEs and developers to make the necessary progress to meet the deadlines to receive the ITC or PTC. The Joint Parties explain, "…resource development timelines remain extended with timeline bottlenecks in the deliverability study and interconnection processes."[22] As the Joint Parties state, the bottlenecks in getting new resources online largely stem from a lack of available interconnection capacity and upgrades needed to support new resource interconnection. They do not stem from LSEs' ability to contract for new resource development.

While the Joint Parties suggest that, "LSEs lack procurement orders for the 2028-2032 timeframe," and do not appear to be voluntarily filling post-2028 needs,[23] LSEs have demonstrated the ability to contract for new build in excess of procurement orders. Progress on the MTR procurement orders shows that aggregate CCA procurement well exceeds their share of identified needs.

22 Joint Parties Proposal, at 5.
23 *Id.*, at 13.

Figure 2: Cumulative CCA Progress on MTR Orders as of June 2025



The primary challenge is, therefore, getting contracted resources interconnected in a timely manner given resource development challenges such as delays to upgrades completed by the IOUs needed to interconnect new resources. If the Commission finds a near-term need, the most effective approach to address the need would be to focus on removing those bottlenecks to expedite the interconnection of contracted resources rather than layering on additional procurement orders and exacerbating existing bottlenecks.

B. Party Recommendations for Overly Prescriptive RCPPP Frameworks that Inhibit an LSE's Ability to Manage Uncertainty and Navigate Constraints in an Affordable Manner Should be Rejected

The Commission should also reject several party recommendations that would introduce overly prescriptive RCPPP requirements. These requirements would limit an LSE's ability to manage uncertainty, such as load forecast uncertainty, and navigate market constraints, such as project cost or development timeline, in an affordable manner.

1. The Commission Should Reject LLT-Specific RCPPP Requirements

The Commission should reject proposals from parties including Hydrostor, Inc., BHE Renewables, LLC, and the Long-Duration Energy Storage Council (LDES Council),[24] Advanced Energy United,[25] and Green Power Institute[26] that would introduce separate requirements for LLT resources. To ensure LSEs can effectively determine whether to include LLT resources in their procurement plans, the Commission should regularly study procurement needs at least ten years out and provide indicative, non-binding procurement requirements for years T+5 through T+9 so that LSEs are informed of their potential procurement requirements well into the future. The Commission should also work with the CAISO to plan for transmission infrastructure needs farther than ten years out in the IRP planning track to provide certainty to market participants about where transmission infrastructure will exist when planning their procurement.

Allowing LSEs to make their own procurement decisions, as opposed to prescribing procurement of specific technology types, will allow the market to decide the most cost-effective projects to pursue that possess the right attributes to meet reliability and GHG-reduction targets. As explained in section II.B.2 below, LLT resources have been procured *above* the cost of new entry (CONE) specifically to meet LLT requirements from the MTR order, rather than other more cost-effective resources. If LLT resources are the most cost-effective way to obtain all the attributes necessary to meet reliability needs, then LSEs will procure them to meet their compliance obligations. RCPPP does not need an LLT-specific requirement for these needs to be met.

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[24] *See generally* joint proposal of Hydrostor, Inc., BHE Renewables, LLC, and the LDES Council.

[25] *See* Advanced Energy United Opening Comments, at 5.

[26] *See* Green Power Institute Opening Comments, at 7.

2. The Commission Should Reject Proposals to Tie Procurement Requirements to Individual LSE IRPs or the PSP

The Commission should not be swayed by party recommendations that the RCPPP must order the procurement of resources consistent with those in the PSP. The California Wind Energy Association's (Calea) claims its proposal will, "[harmonize] the RCPPP with the Commission's [IRP] process and the [PSP] that it produces" and in so doing, "it will drive toward the PSP's least-cost, resource-diverse, reliable portfolio while providing individual LSEs with compliance flexibility."[27] CalWEA's proposal fails to recognize that the PSP is only the least cost on an assumption-driven planning basis. That is, the LSEs make assessments of their portfolio need and the costs of various resources to fulfill that need. If the aggregate of LSE plans leaves an open need for reliability or non-emitting resources, the Commission can evaluate how to fill that open position on a presumed least cost basis relying on net CONE.

The reality of procurement does not align perfectly with the planning assumptions used to develop the PSP and, therefore, what is least cost and available at the time of entering into a power purchase agreement (PPA) may differ from the assumptions. CalCCA surveyed its members, receiving responses from 12 members representing over five million customers and 205 terawatt hours of energy sales annually. When asked if the CCA had selected any non-solar and non-storage resources in recent (*i.e.,* in the last five years) request for offers (RFO), a very small fraction said that they had done so because the resource was priced at or below net CONE. Instead, most were procured at costs above net CONE and most of those were the result of meeting MTR requirements for LLT resources or base load non-emitting resources. In addition, CalCCA asked if the CCAs had declined offers from non-solar/non-storage resources over that same time frame. Most entities indicated that there were no or very few offers that they declined.

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[27] CalWEA Opening Comments, at 2.

In addition to those CCAs, one indicated that it received a reasonable number of offers but like other CCAs, they declined the offers as they were above the net CONE value and not economic compared to other alternatives to fill their portfolio needs.

The PSP can only be the least-cost, reliable, and clean portfolio if there are resources offered at prices that are consistent with the assumptions set in the PSP. For these reasons, the Commission should not focus on procurement that is consistent with the PSP and instead focus on whether the LSE procurement meets reliability and clean energy needs. LSEs, as the procuring entities, are best situated to evaluate the cost of alternatives to procure at least cost while meeting reliability and GHG-reduction objectives. Forcing LSEs to conduct procurement that aligns with specific identified resources in the PSP would likely result in higher costs for ratepayers. Worse, LSEs may end up procuring resources that have higher development risk and are less likely to achieve commercial operation in a timely manner to serve reliability and clean energy needs.

3. The Commission Should Not Extend Binding Requirements Beyond T+4 or Establish Excessively High Procurement Requirements in the Out Years

The Commission should reject recommendations from multiple parties, including TURN[28] and the California Energy Storage Alliance (CESA),[29] to extend binding requirements beyond T+4 or establish excessively high requirements for T+2 through T+4. TURN recommends extending binding forward obligations out to 10 years, stating:

[28] TURN Opening Comments, at 4.
[29] CESA Opening Comments, at 13-14.

> A longer forward horizon would provide advance warning of any potential future capacity scarcity, allow adequate time to address deficiencies, and reduce the likelihood of price escalation in response to tight supply conditions. It often takes more than four years after the issuance of a Commission procurement order for new resources to be developed.[30]

This recommendation should be rejected for several reasons. ***First***, the Staff Proposal includes an assessment of needs at least 10 years forward.[31] Needs identified in years T+5 through T+9 should serve as indicative targets, as proposed in the Staff Proposal. These advisory targets will provide LSEs with the "advance warning" TURN seeks of potential short positions so they can plan their procurement further out (*e.g.,* for LLT resources that take longer than five years to be developed or hedging of future new clean resource price risk). Such advisory targets will avoid putting unnecessary and overly restrictive prescriptions on when LSEs need to make procurement decisions. ***Second***, requiring binding showings more than five years out forces LSEs to make unnecessarily risky deals with projects that may be speculative and with too much uncertainty in the load forecast. ***Third***, in the current market where parties are facing supply chain interruptions, import tariffs, and delays to permitting and interconnection, LSEs are finding that having flexibility to adjust their portfolios before locking them in for compliance will aid in getting more resources under contract and online in an affordable manner.

CESA recommends a 100 percent contracting requirement through T+4 and states that, "longer contracting lead times [are] needed" regardless of whether Option 1 or Option 2 is selected, "because it de-risks project development and aligns with critical processes at the CAISO."[32] Like TURN's recommendation, CESA's recommendation would severely limit LSEs' flexibility to set their own hedging strategies for mid to long-term procurement and to

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30 TURN Opening Comments, at 4.
31 Staff Proposal, at 4-5.
32 CESA Opening Comments, at 13.

manage their portfolios in light of market conditions and uncertain impacts of electrification and large loads. It also exceeds the 90 percent requirement established in the RA program for T+1. Needs identified in years T+0 through T+4 should be met with binding showings of new and existing resources at increasing percentages of needs as they get closer.

III. A RELIABILITY FRAMEWORK COUPLED WITH A CLEAN ENERGY STANDARD ALLOWS LSEs TO BEST OPTIMIZE THEIR PORTFOLIOS TO ADDRESS BOTH RELIABILITY AND CLEAN ENERGY NEEDS IN AN AFFORDABLE MANNER

CalCCA disagrees with ACP-CA,[33] The Public Advocates Office at the California Public Utilities Commission (Cal Advocates),[34] and CAISO[35] who state that without an express new build requirement, there will be insufficient incentives for new build. As stated by PG&E, "LSEs will be procuring new resources to meet their GHG-emissions reduction goals, making a new build requirement within the reliability paradigm duplicative and unnecessary."[36] This has proven true over the last several years, in which LSEs have been procuring to meet RPS obligations in addition to MTR obligations, and CCAs have been procuring to meet policies adopted by their governing boards. Figure 2 above shows CCAs have demonstrated the ability to contract for new build well in excess of the MTR procurement order. In addition, SCE's Opening Comments provide data indicating <u>*other*</u> drivers having more significant impacts on new resource build than the MTR procurement orders:

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33 *See* ACP-CA Opening Comments, at 7.
34 *See* Cal Advocates Opening Comments, at 5-6.
35 *See* CAISO Opening Comments, at 4-5.
36 PG&E Opening Comments, at 14.

> Based on Staff's July 2025 summary of MTR compliance by LSEs, 7,449 MW NQC was online through 2024, which is 551 MW less than the 8,000 MW ordered to be online by June 1, 2024. However, factoring in *resources procured through MTR, RPS, and other procurement efforts, 17,121 MW September NQC of new reliability resources have come online* between January 1, 2020[,] and May 6, 2025, and nearly 15,000 MW NQC is expected to still come online through 2028.[37]

SCE expresses concern about the ability for the CES framework based on actual emissions to effectively achieve sufficient GHG reductions.[38] However, SCE's data demonstrates procurement resulting from the RPS program and other efforts have resulted in contracts above and beyond those from reliability-based procurement orders.

Therefore, the Commission should consider reliability and GHG-reduction frameworks together when determining whether they will sufficiently drive the procurement needed to meet both objectives in the most cost-effective manner. Under the SOD RA program, LSEs need to show sufficient capacity to meet reliability needs in all 24 hours. Currently, RA requirements in hours that are difficult to decarbonize are often met by gas. As the state progresses towards 2045, more clean resources will become available to the market and CES requirements will increase. Taking SOD RA requirements, market dynamics, and CES requirements together, economics will likely drive LSEs to clean portfolios that satisfy both RA *and* CES requirements, rather than to a set of resources that meet RA needs and a different set of resources that meet CES needs. It is highly unlikely for LSEs to simultaneously procure large amounts of emitting resources to meet their RA

37 SCE Opening Comments, at 23 (emphasis added) (footnote omitted).

38 SCE Proposal at, 3-4 ("An hourly accounting system is necessary to develop a portfolio that can most effectively achieve sufficient GHG reductions because it incentivizes LSEs to procure clean energy that can be delivered during the evening net load peak hours when the system is most reliant on gas generation. Further, requiring clean energy… A key defect of the CES framework as proposed in the Staff Proposal is that its percentage-of-annual-sales requirement incentivizes the procurement of clean energy output without consideration of load requirements, hours of need, or a resource's effective GHG reduction.").

requirements and large amounts of RPS-eligible and/or zero-carbon resources to meet their clean energy targets without risking over-procurement that may result in increased customer costs.

CalCCA therefore agrees with GPI that, "resource portfolio development should be co-optimized to *simultaneously achieve reliability and CES targets*."[39] A new plus existing reliability framework using the SOD methodology coupled with the CES best allows LSEs to accomplish this objective. As stated by the California Large Energy Consumers Association (CLECA), "[a]rtificial distinctions between new and existing resources will lead to arbitrary procurement decisions."[40] This artificial distinction will not allow LSEs to achieve targets in the most cost-effective manner and should be rejected.

IV. GIVEN THE UNCERTAINTY AND MISALIGNMENT CREATED BY MELCC EVEN IF MELCC VALUES ARE BOUNDED, THE COMMISSION SHOULD ADOPT A SOD METHODOLOGY FOR RCPPP AS RECOMMENDED BY NUMEROUS PARTIES

Thirteen parties express support for using the SOD accounting methodology for RCPPP requirements.[41] These parties largely recognize that LSEs will need to build a portfolio that meets RA SOD requirements and therefore any benefit of a common denomination of NQC via mELCC is largely lost since all LSEs must consider their RA position in all hours and not just a single measurement. The advent of SOD has meant that there is no longer a single capacity value for a resource. As such, negotiations between buyer and seller must account for hourly portfolio needs, even if a mELCC were in place for RCPPP. Because LSEs must meet both RA and

39 GPI Opening Comments, at 13. (emphasis added).
40 CLECA Opening Comments, at 8.
41 *See* ACP-CA Opening Comments, at 4-5; Advanced Energy United Opening Comments, at 3; AReM Opening Comments, at 3-11; Ava Community Energy Opening Comments, Attachment A, at 2; the California Environmental Justice Alliance, Sierra Club, and Center for Energy Efficiency and Renewable Technologies Opening Comments, at 19-22; CLECA Opening Comments, at 4; GPI Opening Comments, at 3; PG&E Opening Comments, at 10; SDG&E Opening Comments, at 17; SVCE Opening Comments, at 6-7; and CalCCA Opening Comments, at 12-14.

RCPPP requirements, mELCC values would largely be supplanted by hourly SOD values. The Commission should therefore strongly consider efficiency in procurement and certainty that an LSE needs to enter into a long-term investment with a resource. Since this certainty is already provided by SOD, the Commission should adopt that approach for RCPPP.

Further, of the entities that support a mELCC, many support bounding the mELCC.[42] The main reason for bounding is to address the uncertainty of mELCC values, which is already resolved by using the SOD accounting system instead. Using a bounded mELCC will result in an inaccurate and potentially unreliable result. This inaccuracy would then be borne by changes in the PRM. In effect, a bounded mELCC suffers the worst of two worlds with uncertainty about values in the distant future and potential impacts on the PRM.

CalCCA recognizes that any inaccuracy in the portfolio procured under SOD would also result in changes to the PRM. However, a system-wide portfolio procured to meet SOD is not likely to have a vastly different reliability impact than one that is developed using a mELCC since both methods are attempting to assure that the fleet of available resources meets a 0.1 LOLE.

While both models can produce a reliable outcome, using two methods and always complying with the most restrictive standard significantly disrupts procurement and increases costs. The Commission should, therefore, pursue SOD accounting for RCPPP. Workshops to implement RCPPP can address the details necessary to ensure that SOD accurately depicts grid needs.

V. THE COMMISSION SHOULD ADOPT PARTY RECOMMENDATIONS TO PLAN FOR A 0.1 LOLE RELIABILITY TARGET RATHER THAN APPLY A BUFFER OR CCR

The Commission should decline to adopt a buffer or CCR for the reasons expressed by the Alliance for Retail Energy Markets (AReM). AReM states that a buffer or CCR is

[42] *See* Cal Advocates, at 25; ENGIE North America, Inc. Opening Comments, at 10; and SEIA/LSA Opening Comments, at 7.

unnecessary because the RA PRM is already established as a buffer to ensure adherence to a 0.1 LOLE planning standard.[43] CLECA's and the California Coalition of Large Energy Users' (CLEU) Opening Comments support this point.[44] In addition AReM notes that the buffer will not address the root causes of the risk of project delays, which are primarily supply chain and transmission constraint related.[45] Finally, AReM states that "there is no factual basis or evidence to support the 2.5 [percent] buffer value as opposed to any other." [46] This is all the more concerning since the RA PRM based on a 0.1 LOLE already provides for a studied level of buffer as an industry-accepted best practice. In sum, AreM suggests that an additional buffer is both unnecessary and unsupported.

CalCCA agrees with AReM, CLECA, and CLEU that an administratively set and unsupported buffer or CCR beyond the buffer already available through the PRM based on a 0.1 LOLE will simply result in additional expense to customers for reliability beyond what is necessary for grid operation. This is especially true given LSE procurement already occurs to address the potential for a resource to not make its commercial operation date. The Commission should avoid over procurement during the current affordability crisis and federal climate, both of which make renewable resources more expensive.

Over procurement that could occur through the buffer or CCR could also result in the disorderly retirement of the existing fleet. The CAISO has the reliability must run (RMR) mechanism that it can use to prevent a retirement of a needed resource. If procurement happens in a manner necessary to meet the GHG goals and reliability needs, retirement can occur in an orderly manner that will reduce the reliance on the CAISO mechanism. However, as CLEU points out, an

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43 *See* AReM Opening Comments, at 24-25.
44 *See* CLECA Opening Comments, at 10; and CLEU Opening Comments, at 5.
45 AReM Opening Comments, at 24.
46 *Id.*, at 25.

overbuild of capacity can lead to disorderly retirement as energy prices and RA prices would not support the continued operation of some resources.[47] An over procurement of both the CCR and buffer has significant risk of triggering significant unplanned resource retirement.

CalCCA also continues to oppose using the IOU as a procurement entity for the reasons stated in its opening comments.[48] In addition, CalCCA agrees with SCE that the IOU would not be able to procure while adhering to their competitive neutrality rules since the IOU would be procuring the same product at the same time that all LSEs are procuring to meet reliability needs and procurement obligations.[49] Having an IOU compete with other LSEs who are trying to procure their requirements while the IOU procures excess is a recipe for disaster. The same resources that the IOUs would seek to procure should instead be negotiating with an LSE so that the reliability need and GHG goals can be met, and the LSE can avoid penalties while serving their customers. A CCR could result in an LSE not meeting its requirements due to the competition by the IOU at the same time. The result would be penalties, cost allocation, and customers hedging needs met by an entity that is not their chosen procurement entity.

If the Commission chooses to ignore the over-procurement and unnecessary expense that a buffer and CCR would create, it should first vet the appropriate level of buffer and make it an *LSE* requirement and not a *centrally procured* product. LSEs should retain their own procurement autonomy, and the Staff Proposal does not sufficiently explain why this autonomy should be supplanted by IOU central procurement in this case. To the contrary, CalCCA and AReM have pointed out that the IOUs have not been any more successful at meeting their own

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[47] CLEU Opening Comments, at 5.
[48] CalCCA Opening Comments, at 16-20.
[49] SCE Opening Comments, at 43.

procurement needs in MTR than other LSEs.[50] For these reasons, if the Commission adopts any form of buffer, it should be the responsibility of the LSE and not centrally procured.

VI. THE COMMISSION SHOULD ADOPT A PENALTY STRUCTURE FOR RELIABILITY REQUIREMENTS THAT DIFFERENTIATES BETWEEN RA AND RCPPP PENALTIES, AS RECOMMENDED BY SVCE

The Commission should adopt a robust penalty structure that incents compliance without duplicating other penalty mechanisms. To do so, the Commission should develop a penalty structure that relies upon the RA penalty structure for T+0 and T+1,[51] and a penalty structure based upon net CONE for T+2 through T+4. An example of how this could be implemented was proposed by SVCE.[52] By assessing RA penalties in T+0 and T+1 and net CONE based penalties in T+2 through T+4, the Commission will ensure that LSEs do not face duplicative penalties for the same deficiency, while also ensuring LSEs have incentives to cure any deficiencies and invest in new capacity when needed to meet reliability requirements.

VII. THE COMMISSION SHOULD ESTABLISH A PROCESS FOR EVALUATING RESOURCE AND TRANSMISSION SOLUTIONS TO RELIABLY SERVE LOCAL AREA LOAD IN THE MOST COST-EFFECTIVE MANNER BEFORE ADOPTING LOCAL PROCUREMENT REQUIREMENTS IN RCPPP

The Commission should establish a process for evaluating resource and transmission solutions to reliably serve local area load cost effectively before incorporating a local

50 AReM Opening Comments, at 26; and CalCCA Opening Comments, at 18-20.

51 D.21-06-029 adopted a tiered penalty structure for year-ahead and month-ahead RA deficiencies. *See*, D.21-06-029, *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program,* R.19-11-009, (June 24, 2021): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF. D.23-06-029 adopted an LSE expansion penalty for CCAs and ESPs, and modified the tiered penalty structure. *See*, D.23-06-029, *Decision Adopting Local Capacity Obligations for 2024 - 2026, Flexible Capacity Obligations for 2024, and Program Refinements*, R.21-10-002 (June 29, 2023): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF.

52 *See* SVCE Proposal, Attachment A, at 8.

procurement component into RCPPP. Several parties make recommendations regarding how RCPPP should consider local area needs.[53] For example, CalWEA proposes:

> …the Commission should establish local emission reduction targets, set local procurement targets for LSEs (expected to be primarily storage resources) with load in LRAs (and/or the relevant Central Procurement Entity), and plan transmission to achieve the balance of the local emission reduction targets with system resources.[54]

Local reliability needs are responsible for retention of some of the most polluting generation in the state, undermining the state's decarbonization and environmental justice goals. The amount of generation that must be physically located within a locally constrained area is highly dependent on the transmission available to transmit energy from resources outside the local area. If transmission capacity is limited, resources in the local area are needed to maintain reliability. Today, such resources are often emitting resources. It is therefore critical to the state's policy goals for the Commission to focus on how to reduce reliance on emitting resources in local areas.

The Commission should refrain from adopting a local resource procurement obligation for RCPPP at the outset, until it can develop a process for evaluating transmission and non-transmission alternatives for cost-effectiveness and feasibility given existing land use constraints. Planning for local reliability is a complex task. Local reliability needs can be addressed either by: (1) having sufficient generation physically located within the local area; or (2) having sufficient transmission build to relieve the local area constraints and allow generation outside the local area to be delivered to load within the local area. Local RA requirements can decline if new transmission is built that allows resources outside the local area to be delivered to local area load.

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53 *See* Advanced Energy United Opening Comments, at 6; Bioenergy Association of California, at 9-10; CalWEA Proposal at 5; CEJA/Sierra Club/CEERT Opening Comments, at 13-19; and Green Hydrogen Coalition Opening Comments, at 8-9.

54 CalWEA Proposal, at 5.

In addition, the ability for local-area storage to contribute to local RA needs is dependent upon the CAISO's assessment of the ability of storage resources in the local area to charge given constraints on both internal generation and transmission capacity.

In the OIR for the new IRP proceeding, R.25-06-019, the Commission recognizes the need to further consider how to address local area reliability needs with a reduced reliance on emitting resources. It states, "[t]here is further work to be done focusing specifically on transmission facilities needed to interconnect resources, reliably serve load centers, and reduce dependence on fossil-fueled generation resources in local areas."[55] Given the complex nature of local reliability planning and the additional work needed in R.25-06-019, local resource procurement requirements should not be incorporated into RCPPP at the outset. Instead, the Commission should develop and implement RCPPP such that it ensures system reliability and make the determination of whether a local procurement component is necessary after initial RCPPP implementation and after the Commission has a process in place to evaluate transmission and non-transmission alternatives for cost-effectiveness and feasibility.

The Commission should also refrain from modifying LSEs' local RA procurement obligations outside the RA proceeding. Vistra Corp. (Vistra) recommends the Commission allocate to each LSE its share of system requirements and local requirements, and the local RA CPE would "act as central buyer for any unmet local RA needs in the T+2 solicitation process."[56] This recommendation would be a fundamental change to the RA program that would need to be considered in the RA proceeding. While CalCCA has historically supported a residual CPE model, the RA process has undergone significant changes in recent years. Revisiting the

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55 *Order Instituting Rulemaking,* R.25-06-019 (July 2, 2025), at 13: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K276/571276511.PDF.

56 Vistra Opening Comments, at 5.

role of the CPE in local RA procurement would significantly impact LSE procurement processes and require additional discussion in the RA proceeding.

VIII. PG&E AND SHELL HIGHLIGHT THE NEED TO ENSURE THAT THE RISKS OF CENTRAL PROCUREMENT NOT MATERIALIZING ARE NOT BORNE BY INDIVIDUAL LSES

The Commission must ensure that if CPE procurement by the California Department of Water Resources (DWR) does not materialize as planned, reliability needs continue to be met without shifting risk to LSEs, who "will not have control over the timing or the amount of CPE procurement."[57] In Opening Comments, CalCCA state that in determining how to treat centrally procured resources within the RCPPP, the Commission and stakeholders must consider "…the instance in which CPE procurement falls through and how the Commission would address that shortfall without shifting the development risk of CPE procurement onto LSEs."[58] PG&E's and Shell's Opening Comments further highlight the need to carefully consider how to manage the risk of CPE procurement not materializing.

Shell states:

> … D.24-08-064, in setting LLT resource needs, expressly stated that "DWR is not required to procure all of the [identified] resources and may procure as little as zero, depending on the reasonableness of prices offered by developers." To the extent those resources are not procured, or not fully procured, it falls on LSEs, under the Staff's proposal, to make up that shortfall, potentially on shorter notice, to the detriment of reliability and without any control over whether or when DWR makes procurement decisions for LLT resources. Addressing shortfalls in that manner inappropriately allocates the risk and consequences of under-procurement to LSEs, who have no control over the procurement process.[59]

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57 D.24-08-064, *Decision Determining Need for Centralized Procurement of Long Lead-Time Resources*, R.20-05-003 (Aug. 22, 2024), at 52: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M539/K202/539202613.PDF.

58 CalCCA Opening Comments, at 34.

59 Shell Opening Comments, at 8 (footnote omitted).

Shell highlights that, although LSEs do not have control over CPE procurement processes, the Staff Proposal risks placing the responsibility for curing CPE procurement shortfalls on those LSEs. If this procurement responsibility is placed on LSEs on short notice, outside of the regular RCPPP timeline, this could harm reliability or drive-up costs.

PG&E urges the Commission to "…develop a mitigation plan in the event that DWR fails to procure the full amounts authorized in D.24-08-064 and reliability is potentially impacted."[60] This is because "DWR's procurement will ultimately have an impact on the amount of procurement that is required by LSEs so the interaction and time needed as a mitigation measure cannot be overlooked in the design of the RCPPP."[61] CalCCA agrees with PG&E that a mitigation plan is needed in the event DWR does not procure the full amounts in D.24-08-064. Because the Commission directed DWR to procure *up to* 10.6 GW, LSEs face significant uncertainty around the magnitude of the effect DWR procurement will have on their portfolios and/or RCPPP obligations.

While CalCCA supports the development of a "mitigation plan" as recommended by PG&E, the details of such a plan require additional consideration by the Commission and stakeholders. PG&E's proposal "calls for DWR's contracts to be executed by T+5 in accordance with AB 1373. If contracts are not executed by then, the Commission must take appropriate action to ensure reliability needs will be met between the T+0 through T+4 timeframe. This may include the procurement of bridging resources by DWR or individual LSEs."[62] While PG&E's proposal attempts to provide certainty to LSEs by setting a date for CPE contracting, PG&E's

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60 PG&E Opening Comments, at 29.

61 *Ibid.* Specifically, PG&E's proposal "calls for DWR's contracts to be executed by T+5 in accordance with AB 1373. If contracts are not executed by then, the Commission must take appropriate action to ensure reliability needs will be met between the T+0 through T+4 timeframe. This may include the procurement of bridging resources by DWR or individual LSEs."

62 *Ibid.*

proposal could shift the burden of bridging to individual LSEs without defining the requirements of bridging (e.g., whether the resources need to be LLT, have a specific output profile, etc.). This burden could be significant if CPE contracts are delayed or cancelled at the last minute. The RCPPP design must therefore be carefully crafted such that LSEs do not bear the risk of DWR foregoing procurement or its procurement not coming to fruition due to project delays, cancellations, or other factors.

IX. THE PCIA PROCEEDING IS THE APPROPRIATE VENUE FOR CONSIDERING PARTY RECOMMENDATIONS RELATED TO THE PCIA

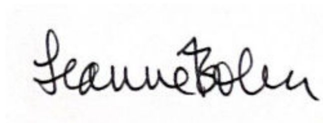
The Commission should defer recommendations related to the PCIA to the PCIA proceeding (R.25-02-005). Some parties make recommendations on how to treat IOU legacy resources and their interactions with LSE procurement.[63] These recommendations are more appropriately considered in R.25-02-005, an open proceeding initiated to consider changes to the PCIA, including: (1) reviewing the market price benchmarks; (2) incorporating RA program changes, including the SOD framework; (3) incorporating Bundled Procurement Plan guidance; (4) reducing rate volatility; and (5) providing guidance for PCIA resource vintaging.

[63] *See* ACP-CA Opening Comments, at 36 ("Compliance credit for IOU legacy resources could be allocated pro rata, reflecting their legacy role serving CAISO, could be allocated to LSEs based on their share of a specific distribution utility service territory's load, or could be allocated in some other framework consistent with policy outcomes from the Power Charge Indifference Adjustment ("PCIA") proceeding. In the event that an LSE procures a new-build hydroelectric or nuclear resource, appropriate crediting adjustments could take place to reflect these investments."); and GPI Opening Comments, at 9 ("As the RCPPP framework is developed, it may be prudent to consider if IOU existing contracts and load departure combined with IRP MTR new procurement orders, and under RCPPP-Reliably Option 1, will force the majority of new procurement on CCAs due to past load transfers. If this is the case, a limited time LSE portfolio re-optimization and right sizing via a PCIA/VAMO mechanism in the early stages of RCPPP implementation may be valuable for "resetting" existing resource distributions and leveling new resource capacity and CES procurement needs across LSEs").

X. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests consideration of the reply comments herein and looks forward to an ongoing dialogue with the Commission and stakeholders.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy
General Counsel
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

August 5, 2025

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

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO AMERICAN CLEAN POWER – CALIFORNIA MOTION TO AMEND THE AMENDED SCOPING MEMO TO INCLUDE AN ADDITIONAL TRACK FOR EXPEDITED PROCUREMENT

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Lauren Carr,
Senior Manager, Regulatory Affairs and Market Policy
Eric Little,
Director of Market Design

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

August 5, 2025

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SUMMARY OF RECOMMENDATIONS

The Commission should reject ACP-CA's[1] Motion because it:

- Is not based upon a demonstrated reliability or RPS need;
- Is based on unsubstantiated claims of ratepayer savings;
- If granted, will result in a near-term procurement order that will likely result in increased market prices and cause significant market distortion at a time when LSEs are procuring to meet MTR, RPS, and other requirements; and
- Fails to recognize the many factors that will impact the ability of a resource to obtain ITC or PTC.

[1] Acronyms used here are defined in the body of CalCCA's Comments.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S RESPONSE TO AMERICAN CLEAN POWER – CALIFORNIA MOTION TO AMEND THE AMENDED SCOPING MEMO TO INCLUDE AN ADDITIONAL TRACK FOR EXPEDITED PROCUREMENT

The California Community Choice Association[2] (CalCCA) submits this response pursuant to Rule 11.1(e) of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure[3] to the *American Clean Power – California Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*[4] (Motion), dated July 21, 2025. The Motion seeks to amend the most recent scoping memo in this proceeding to include a new emergency procurement track separate from procurement proposed under the pending Reliable and Clean Power Procurement Program (RCPPP). American Clean Power – California's (ACP-CA) requested new procurement track would be for the purpose of the Commission ordering "immediate" and "unbounded" near-term procurement by the investor-

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

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

4 *American Clean Power – California Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*, Rulemaking (R.) 20-05-003 (July 21, 2025).

owned utilities (IOUs) on behalf of the system to ensure that California ratepayers benefit from tax credits that are soon to be phased out due to the recently passed Federal legislation in the One Big Beautiful Bill Act (OBBBA)."[5]

I. INTRODUCTION

ACP-CA's largely unsubstantiated motion suffers from four fatal flaws and therefore should be rejected. First, ACP-CA fails to base its motion on any Commission (or other) rigorous study of ***need*** for the requested "unbounded" procurement. Rather, ACP-CA bases its requests on unvetted proposals regarding near-term procurement filed July 15, 2025, by itself and other stakeholders in response to the RCPPP Staff Report.[6] ACP-CA also cites to the Integrated Energy Policy Report (IEPR) Load Forecast, which includes speculative and uncertain data center load and which needs further vetting prior to becoming the basis for a procurement order. Without a definitive need derived through a meaningful process, an order to procure is unwarranted.

Second, ACP-CA cites only its back of the envelope "potential savings from capturing incremental resources [the pool of which is still "unclear"] eligible for tax credits" in support of its broad statement that "affordability objectives" will be met through the procurement "by ensuring that resources needed for reliability and to meet the IRP goals are procured at ***least cost*** to ratepayers."[7] ACP-CA fails to substantiate its statement that the procurement will provide "the greatest overall value to California ratepayers."[8] In fact, there are no guarantees of the prices developers will offer for these projects. As noted in the third and fourth points below, requiring

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5 Motion, at 1; OBBBA, H.R. 1 (July 4, 2025) (modifying energy tax provisions in the Inflation Reduction Act of 2022 (the IRA), and accelerating the phaseout of the technology-neutral tax credits, Section 45U Clean Electricity Production Tax Credit (PTC) and Section 48E Clean Electricity Investment Tax Credit (ITC)).

6 *See Email Ruling Granting Request for Extension of Time*, R.20-05-003 (May 15, 2025). Reply comments to the July 15, 2025, proposals are due August 5, 2025.

7 Motion, at 6.

8 *Id.*, at 8.

additional procurement in the current market will likely result in increased prices, negatively impacting ratepayers.

Third, such a near-term procurement order will likely result in increased market prices and cause significant market distortion at a time when load-serving entities (LSEs) are procuring renewable capacity to meet other compliance requirements. These requirements include mid-term reliability (MTR), renewables portfolio standard (RPS), and individual goals set by governing boards. Placing more demand in the market will likely drive-up prices. The Commission should avoid creating such market distortions whenever possible.

Finally, ACP-CA fails to recognize that procurement of resources is challenged not only by the expiration of the credits but also by many other factors. Recently issued Federal guidance regarding the review of wind and solar resources, coupled with supply chain issues, interconnection difficulties, and permitting delays, add significant risk to meeting deadlines and could contribute to potential non-compliance. Each of these issues affects the ability of any LSE, whether individually or through central procurement, to bring these resources to their commercial operation date (COD).

The Commission should therefore reject the Motion because it:

- Is not based upon a demonstrated reliability or RPS need;
- Is based on unsubstantiated claims of ratepayer savings;
- If granted, will result in a near-term procurement order that will likely result in increased market prices and cause significant market distortion at a time when LSEs are procuring to meet MTR, RPS, and other requirements; and
- Fails to recognize the many factors that will impact the ability of a resource to obtain ITC or PTC.

II. ACP-CA'S CLAIMS OF PROCUREMENT NEED DO NOT MEET THE RIGOROUS ANALYSIS NECESSARY FOR THE COMMISSION TO ORDER PROCUREMENT

ACP-CA's mere claims of procurement need, based on proposals made by parties in RCPPP Opening Comments, fail to meet the rigorous analysis required for the Commission to order procurement. As set forth below, ACP-CA's Motion: (1) fails to meet the statutory needs assessment necessary for a Commission procurement order; (2) fails to recognize the speculative nature of the current IEPR load forecast, due to the inclusion of uncertain data center and large load, which needs scrutiny prior to forming the basis of a procurement order; and (3) is based on observations in RCPPP Opening Comments that have not yet been tested or scrutinized. As a result, ACP-CA's Motion should be rejected.

A. The Commission Has Not Made a Determination of Need for Centralized or LSE Specific Procurement

The Commission has not made a determination of need that would justify the mandatory, centralized procurement proposed by ACP-CA for the specified timeframe. Such a determination is a necessary prerequisite to any procurement mandate, particularly one requiring the three IOUs to procure on behalf of all customers using the Cost Allocation Mechanism (CAM). ACP-CA fails to justify its request that procurement be centralized given the preference should always be that LSEs procure for their own customer's needs. Indeed, Public Utilities Code section 366.2 enabling CCAs recognizes that "CCAs shall be solely responsible for all generation procurement activities on behalf of the [CCA's] customers."[9] While section 366.2 also states that the Commission can require "other generation procurement arrangements expressly authorized by

9 Public Utilities Code § 366.2(a)(5).

statute,"[10] ordering centralized procurement to leverage short-term economic incentives such as the ITC or PTC has not been expressly authorized.

A rigorous needs assessment is essential to ensure that any action taken is justified, appropriately scaled, and in the best interest of ratepayers. The statutes relied on by ACP-CA, sections 365.1(c), 454.51, and 454.52, to allow the Commission to order centralized procurement for the system, universally require demonstrating "need" for such procurement.[11] Indeed, section 454.52 requires the Commission to conduct "probabilistic reliability modeling" to ensure sufficient capacity for short and midterm reliability needs, and to review the results of that modeling in a public proceeding. Previous procurement orders, including D.19-11-016[12] and D.21-05-035[13] have only been issued after the Commission conducted substantial analysis regarding such need.

While Energy Division staff have discussed the possibility of an interim procurement order if the RCPPP implementation is delayed, they have not proposed doing so without conducting a comprehensive analysis of need. That analysis must include, at a minimum:

- An evaluation of the current resource inventory;
- The status and projected results of MTR procurement; and
- Updated load forecasts for the target period.

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[10] *Ibid.*

[11] *See id.,* § 365.1(c) (referring to an IOU "obtain[ing] generation resources that the commission determines are ***needed*** to meet system or local area reliability needs for the benefit of all customers"), § 454.51(a) (requiring the Commission "identify a diverse and balanced portfolio of resources ***needed*** to ensure a reliable electricity supply that provides optimal integration of renewable energy and resource diversity in a cost-effective manner"), and § 454.52 (describing the IRP process and requiring the Commission to "aggregate reported short-term and midterm resource procurement from all [LSEs]" under the RA and IRP statutes "in furtherance of avoiding unplanned energy supply shortfalls or expensive emergency procurement and ensuring a more accurate understanding of electrical grid operational ***needs***").

[12] D.19-11-016, *Decision Requiring Electric System Reliability Procurement for 2021-2023,* R.16-02-007 (Nov. 13, 2019).

[13] D.21-06-035, *Decision Requiring Procurement to Address Mid-term Reliability (2023-2026),* R.20-05-003 (June 30, 2021).

Only once this analysis is complete can the Commission responsibly determine first whether additional procurement is necessary and second, whether that procurement should be centralized and subject to CAM cost allocation.

B. The Current IEPR Forecast Has Not Been Evaluated to Form the Basis of Need and Contains Elements That are Highly Speculative

A procurement order also should not be based on the current IEPR load forecast, as advanced by ACP-CA.[14] The current IEPR load forecast includes significant increases in electricity demand, much of which stems from assumptions about future data center development. These assumptions are highly speculative and have not yet been sufficiently scrutinized to serve as the basis for procurement mandates.

ACP-CA cites to load growth projected by the 2024 IEPR in the 2028–2032 period, as shown in Figure 1, below.

Figure 1 - CEC 2024 IEPR Load Forecast Aggregate for PG&E, SCE, and SDG&E areas

Year	2025	2026	2027	2028	2029	2030	2031	2032
Retail Sales (TWh/yr)	199.9	205.1	212.6	225.7	237.7	249.8	261.6	271.3
Percent Change from 2025	0%	3%	6%	13%	19%	25%	31%	36%

ACP-CA points to RCPPP Comments from Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and The Utility Reform Network (TURN referencing load growth in the 2028 to 2030 or 2032 range, as representing an increase of load between 13 percent and 36 percent.[15] However, using the California Energy Commission's (CEC) energy consumption data files and evaluating actual energy served for the aggregate of the three utilities reveals that a 13 percent load growth took 26 years from 1997 to 2023 to obtain, and a 36 percent load growth took longer than the data provided by the CEC, which goes back to 1990.[16] The level

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14 *See* Motion, at 4-5.

15 CEC 2024 IEPR Baseline forecast aggregated for the three IOUs.

16 CEC Energy Consumption Data files contain information going back to 1990 which indicate the change in consumption between 1990 and 2023 (the last date of recorded data) was only 21 percent.

of load growth depicted in the 2024 IEPR is unprecedented and primarily driven by anticipated load growth due to data centers.

This data center load growth is unknown and speculative. At a CEC July 16, 2025, Demand Analysis Working Group meeting, multiple presentations were provided regarding anticipated data center load growth. A presentation from PG&E included a bullet stating, "[f]or multiple forecast cycles, forecasts will likely be highly uncertain due to the nascency of the data center technology & markets and due to the complexity of data center projects."[17] At the same meeting, SCE presented that they had increased the likelihood of eight projects, decreased the likelihood of nineteen projects, and maintained the likelihood of sixteen projects.[18]

The high degree of variability in data center growth deserves a more complete dialogue and evaluation before using the current IEPR load forecast as a basis for ordering any interim procurement, let alone a directed procurement by the IOUs on behalf of all customers.

C. Needs Incorporated in RCPPP Opening Comments and Used as Support for APC-CA's Motion are Unsubstantiated and Cannot Be Relied on for a Procurement Order

While ACP-CA points to four parties' comments in the RCPPP proceeding as supporting a need, the proceeding will only be at the point of reply comments when this response is due. There has been no process to evaluate those claims of need, understand the assumptions behind them, offer other inputs that should be accounted for, or provide testimony or cross-examination if necessary. Further, not all of the four parties advocate for a need. The first sentence from the CAISO that ACP-CA quotes acknowledges that they do not suggest a need exists. Rather, the CAISO states, "[t]o advance a *near-term needs assessment* and *potential* procurement order."[19]

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17 Demand Analysis Working Group Meeting (July 16, 2025).
18 *Ibid.*
19 CAISO RCPPP Opening Comments, at 3.

The CAISO goes on to state, "[e]stablishing a track dedicated to *near-term needs assessment analyses* of resource sufficiency in 2028-2032 *to support a potential new procurement order* as soon as the end of 2025."[20] Indeed, the CAISO does not state that there is a need but rather that the Commission should *determine* if there is a need.

TURN likewise does not conclude that there is a near-term need. Instead, they argue an immediate procurement order should be issued to address the potential for increased costs.[21] Their comments do not state that without such procurement, California will fail to meet either RPS or RA reliability needs.

ACP-CA also cites SCE as noting a 26 percent gap between the clean energy share projected for 2028 when compared to the target.[22] The target referred to is an amount that Energy Division staff provided as an "illustrative example" with an "indicative" value.[23] SCE's point in the discussion was that the amount of procurement this would drive in the time frame it would be required is "an unrealistic build-out."[24] SCE uses this to suggest that the timeframe for compliance with such a new standard should be delayed to ensure a market sufficient to meet the obligation, and not that such procurement should be expedited as ACP-CA recommends.

The ACP-CA, Independent Energy Producers Association (IEPA), Large-Scale Solar Association (LSA), and Solar Energy Industries Association (SEIA) RCPPP Opening Comments (the Joint Proposal) references a shortfall of the 2023 preferred system plan to meet RPS needs.[25] It is reasonable to conclude that LSEs will adjust their portfolios to meet compliance

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20 CAISO RCPPP Opening Comments, at 3 (emphasis added).
21 TURN RCPPP Opening Comments, at 1-2, and 24.
22 Motion, at 4 (citing SCE RCPPP Opening Comments, at 10).
23 *See Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, *Attachment A: Staff Proposal: Reliable and Clean Power Procurement Program* R.20-05-003 (Apr. 29, 2025), at 45.
24 SCE RCPPP Opening Comments, at 10.
25 ACP-CA, IEPA, LSE, SEIA RCPPP Opening Comments, at 2-5.

requirements as they evaluate the market and actual load. Those LSEs already out procuring to meet RPS needs would face significant market pressure if the Commission decided to order the IOUs to enter into any and all long-term agreements with ITC/PTC eligible resources that can meet the construction and COD requirements under OBBBA. As SCE pointed out in their opening comments, while the MTR has generated 7,449 MW of net qualifying capacity (NQC) reaching COD through 2024, the total amount of new resources brought to COD through MTR, RPS, and other procurement totals 17,121 megawatts (MW) of September net qualifying capacity (NQC).[26] The Commission and ACP-CA should not presuppose that the only manner to get new resources built is through an MTR type of order, nor should they assume that sending an additional several thousand MW demand into a constrained market is a prudent measure even in the face of expiring ITC and PTC incentives.

Finally, ACP-CA refers to an analysis by PG&E claiming a shortfall of 2,900 MW of NQC equivalent capacity needed for storage charging sufficiency (*i.e.,* generation necessary to fully charge the expected fleet of storage) by 2030. However, the information provided by PG&E to arrive at this figure does not reveal information necessary to assess its accuracy. As an example of an issue that would deserve further discussion, the Commission currently does not report the status of contracts of new resources with LSEs beyond 2028. Since the analysis of PG&E goes out to 2030, the Commission would need to better understand the contractual status of resource development targeted for those two years to evaluate whether the need predicted by PG&E is correct. In addition, as noted in section II.B, there is significant uncertainty in the load forecast upon which PG&E's analysis is based.

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[26] SCE RCPPP Opening Comments, at 23.

For all of these reasons, ACP-CA's unsubstantiated assertions of need for a procurement order should not form the basis for a Commission procurement order. Rather, any such order will require rigorous examination and modeling of a multitude of factors to determine whether procurement is needed.

III. ACP-CA HAS NOT SUBSTANTIATED AND CANNOT SUBSTANTIATE ITS CLAIMS OF CUSTOMER SAVINGS

ACP-CA offers only back-of-the-envelope "potential savings from capturing incremental resources [the pool of which is still "unclear"] eligible for tax credits" in support its motion. Based on these rough estimates, it boldly claims that "affordability objectives" will be met through the procurement "by ensuring that resources needed for reliability and to meet the IRP goals are procured at ***least cost*** to ratepayers."[27] To make such a determination, however, would involve a wide range of variables and uncertainties.

As a preliminary matter, the Commission should ask why, if these projects are a great fit at a great price, they have not yet been procured. Have they been offered into all LSE solicitations in the past? At what prices have they been offered? If ACP-CA's claim had merit, the projects whose dance cards apparently have not been filled would already be out on the dance floor with an LSE.

In addition, while claiming that this procurement will be "least cost," there are no guarantees of the prices developers will actually offer for these projects. Again, if the developers were unable to sell their projects to LSEs *before* OBBBA, possibly because of the prices they sought, will providing increased leverage for central procurement improve the situation?

Two more uncertainties, discussed below, could affect customer savings. Section IV. suggests that giving these projects a ready-built home with the IOUs could make LSE

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27 Motion, at 6 (emphasis added).

compliance with procurement requirements more challenging and distort market results, raising the cost of procurement. Section V. further explains how the success of ACP-CA's proposal could be hindered in a variety of other ways that could also increase costs.

IV. THE REQUESTED RELIEF WILL CONFLICT WITH OTHER ONGOING PROCUREMENT EFFORTS SEEKING THE SAME RESOURCES

At the same time ACP-CA's Motion would have the IOUs out procuring all wind and solar resources in the CAISO interconnection queue cluster 14, all LSEs are attempting to procure to meet their own needs, including meeting MTR, RPS, and internal goals. Those same LSEs are also aware of the potential cost implications of the expiring ITC and PTC. While ACP-CA proposes to allow CCAs and ESPs that procure above their own MTR needs to use that excess to offset any costs that would be allocated to them by the IOU, they fail to acknowledge that the rapid and significant increase in demand will have an impact on prices.

In July 2025, the Commission issued a status report on MTR procurement that shows procurement is still necessary to meet the MTR goals. For 2024 obligations, the report shows a 551 MW shortfall and notes that some compliance was achieved by using bridge resources, meaning the total need for new resources exceeds 551 MWs.[28] The report goes on to show that 16,300 MW of capacity remains to be brought online or verified by staff from 2025 through 2027.[29] While it is possible that much of this contracting has been achieved and resources are progressing toward COD, there is also likely still demand in the market for queue cluster 14 resources. Sending the IOUs into that market with a demand for every wind and solar resource in the queue will force demand to exceed supply. This would be similar to what has happened with

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[28] *California Public Utilities Commission (CPUC) Staff Review of Load-Serving Entities' (LSEs') Compliance with the Mid-Term Reliability (MTR, D.21-06-035) and Supplemental MTR (SMTR) D.23-02-040) Decisions*, (posted July 2025), at 20.

[29] *Id.* at 24.

resource adequacy (RA) in the last two years, resulting in prices that previously averaged around $4/kilowatt (kw)-month to average in excess of $40/kw-month[30] with some prices exceeding $100/kw-month.[31] It is difficult to imagine how this sort of market frenzy proposed by ACP-CA will be in the best interest of consumers, who have already seen dramatic price increases for electricity service. Although it is a good idea to try to obtain the ITC and PTC credits before they expire, existing procurement orders and market constraints are already pushing LSEs to procure all the clean resources they can in a cost-effective manner. Creating artificial market scarcity through the proposed ACP-CA order will only strain this process further.

V. A PROCUREMENT ORDER IS UNLIKELY TO ADDRESS THE AVAILABILITY OF ITC AND PTC

The desire by LSEs to obtain resources that have lower cost due to ITC and PTC is challenged not only by the expiration of those credits but also by other factors. These factors include other Federal guidance impacting the ability to meet the OBBBA deadlines, supply chain issues, interconnection difficulties, and permitting delays. Each of these issues affects the ability of any LSE, whether individually or through central procurement, to bring these resources to COD.

A. Additional Federal Requirements on Wind and Solar Will Likely Slow Renewable Generation Not Already Underway, Jeopardizing the Ability to Meet Tax Incentive Deadlines

In addition to OBBBA, Federal guidance that requires:

30 *Market Price Benchmark System RA Forecast* (Nov. 5, 2024).

31 FERC Electronic Quarterly Reporting (July 2025).

> [A]ll decisions, actions, consultations, and other undertakings—including but not limited to the following—related to wind and solar energy facilities shall require submission to the Office of the Executive secretariat and Regulatory Affairs, subsequent review by the Office of the Deputy Secretary, and final review by the Office of the Secretary."[32]

This is followed by a list of 69 items that must be reviewed. This process will likely introduce additional delays to bring eligible resources to COD. In addition, Executive Order 14156 declares:

> These numerous problems [referring to precariously inadequate and intermittent energy supply, and an increasingly unreliable grid] are most pronounced in our Nation's Northeast and West Coast, where dangerous State and local policies jeopardize our Nation's core national defense and security needs, and devastate the prosperity of not only local residents but the entire United States population. The United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[33]

Given the required review and the Federal attack on renewable generation, particularly in the West, it is hard to believe that any resource not already under contract and under development, required to undergo this review, will exit this review process before the deadlines of OBBBA.

B. Resource Development is Delayed Due to Many Factors in Addition to Lack of Contracting

Issues of supply chain, interconnection (physical not queue related), and permitting difficulties have been well documented throughout the MTR process. These difficulties have even led to bridge contracting when developing a new resource was not feasible or prohibitively expensive due to the competition for scarce resources. None of these problems are solved by pushing even more demand into an already constrained market. Doing so will not make the

[32] *Departmental Review Procedures for Decisions, Actions, Consultations, and Other Undertakings Related to Wind and Solar Energy Facilities Department of the Interior* (July 15, 2025).

[33] Executive Order 14156, *Declaring a National Energy Emergency* (Jan. 20, 2025).

components more available, the interconnection completed more timely, or speed up the permitting process. Any of these individually is a significant threat to meeting the timeline specified in OBBBA, and taken together, cast serious doubt on the ability of any LSE, let alone an IOU acting on behalf of all LSEs, to make the necessary progress to meet the deadlines to receive ITC or PTC.

VI. IF THE COMMISSION ADOPTS ACP-CA'S PROPOSED PROCUREMENT ORDER, THE SUGGESTED ALLOCATION METHODOLOGY SHOULD BE REJECTED

While CalCCA opposes ACP-CA's Motion and any procurement order resulting from it, if the Commission grants ACP-CA's Motion, the suggested allocation methodology should be rejected. ACP-CA recommends that to the extent a CCA or electric service provider (ESP) procures above their IRP and RPS needs, such procurement should offset the costs that would otherwise have been allocated to them through the IOU central procurement.[34] While the intent may be well-placed, the implementation of this proposal is not equitable. When such "opt-out" provisions have been previously recommended, they are on the basis that the central entity will know that the LSE has opted out and met its obligation or that the central entity procurement will occur after the LSE procurement. This process allows the CPE to adjust its procurement in recognition of what other LSEs have accomplished. The Motion, however, requests the Commission order the IOUs to immediately procure, and to conclude that procurement by the end of 2025. LSEs will continue to meet their IRP and RPS needs beyond that time.

The result could be that the IOU over-procures for the need of those LSEs that did not exceed their IRP and RPS needs. This over-procurement would then be allocated to a smaller group of customers who would pay for procurement in excess of their need (presuming the

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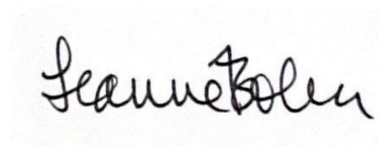
[34] Motion, at 10.

Commission identifies a need as discussed in section II.B). While CalCCA appreciates ACP-CA's efforts to recognize the autonomy in procurement that CCAs and ESPs should retain, the result of the proposal is inequitable and unworkable, and should be rejected.

VII. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests that the Commission deny ACP-CA's Motion.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

August 5, 2025

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Western Electricity Coordinating Council	Docket No. EL10-56-000

JOINT COMMENTS OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION, NORTHERN CALIFORNIA POWER AGENCY, PACIFIC GAS AND ELECTRIC COMPANY, SAN DIEGO GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND THE SIX CITIES ON THE ORDER INSTITUTING INVESTIGATION UNDER SECTION 206 CONCERNING THE WECC SOFT PRICE CAP

Pursuant to Rule 211 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("the Commission" or "FERC"), 18 C.F.R. § 385.211, and the Commission's July 15, 2025 Order Instituting Section 206 Proceeding, Establishing Refund Effective Date, and Extending Deadlines for Cost Justification Filings ("the Order"), Intervenors California Community Choice Association; Northern California Power Agency; Pacific Gas and Electric Company; San Diego Gas and Electric Company; Southern California Edison Company; and the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside California ("the Six Cities") (collectively, the California load-serving entities, or "the California LSEs") submit comments requesting FERC reconsider its proposal to abandon the Western Electricity Coordinating Council ("WECC") soft price cap.

I. BACKGROUND

As the Order notes, pursuant to prior Commission orders, spot market energy sales in WECC are currently subject to a soft price cap of $1,000/megawatt hour ("MWh"), and prices that exceed that amount are subject to cost justification and refund. In August 2020 (and again during the summers of 2021 and 2022), multiple sellers made sales in WECC above the soft price cap. After finding that some sellers had not adequately justified their above-cap sales, the Commission issued refund orders for amounts above the soft price cap or price indices, as applicable. As relevant here, sellers petitioned for review of these orders in the D.C. Circuit, which held that the Commission was required to conduct a *Mobile-Sierra* analysis prior to ordering refunds. *See Shell Energy v. FERC*, 107 F.4th 981 (D.C. Cir. 2024) ("*Shell*"). Because the Commission had not made a finding that *Mobile-Sierra* was inapplicable or that the contract prices above the soft price cap seriously harmed the public prior to issuing the challenged refund orders, the appellate court vacated the refund orders and remanded to the Commission for further proceedings.

The Commission issued the Order in response to the *Shell* decision. Among other things, the Order announces the Commission's proposal to eliminate the existing WECC soft price cap, leaving bilateral markets in the WECC without a price cap.

II. COMMENTS

The Order proposes to abandon the soft price cap, maintaining that evolving market conditions in WECC, Commission enforcement capabilities, and a changed cost-benefit analysis in light of *Shell* have eliminated the need for the soft price cap. The concerns that drove the Commission to institute the soft price cap in 2002, however, remain salient today. As explained below, the Order ignores current market realities, the limitations of the Commission's ex post enforcement resources and abilities, and the important transparency benefits promoted by the soft price cap. In short, the Order does not demonstrate the soft price cap should be removed; to the contrary, the soft price cap remains an important tool in promoting just and reasonable rates. The soft price cap—or some other, comparable ex ante price disciplining mechanism—is necessary to effectuate the Commission's statutory mandate to ensure just and reasonable rates.

III. THE ORDER'S RATIONALES FOR ABANDONING THE SOFT PRICE CAP DO NOT BEAR SCRUTINY.

The Order proposes abandoning the soft price cap for three reasons that, taken individually or cumulatively, do not support the proposed action.

A. The concerns motivating the 2002 soft price cap order remain relevant today, notwithstanding wholesale market developments.

First, the Commission incorrectly asserts that market developments since the establishment of the WECC soft price cap render the soft price cap unnecessary to discipline

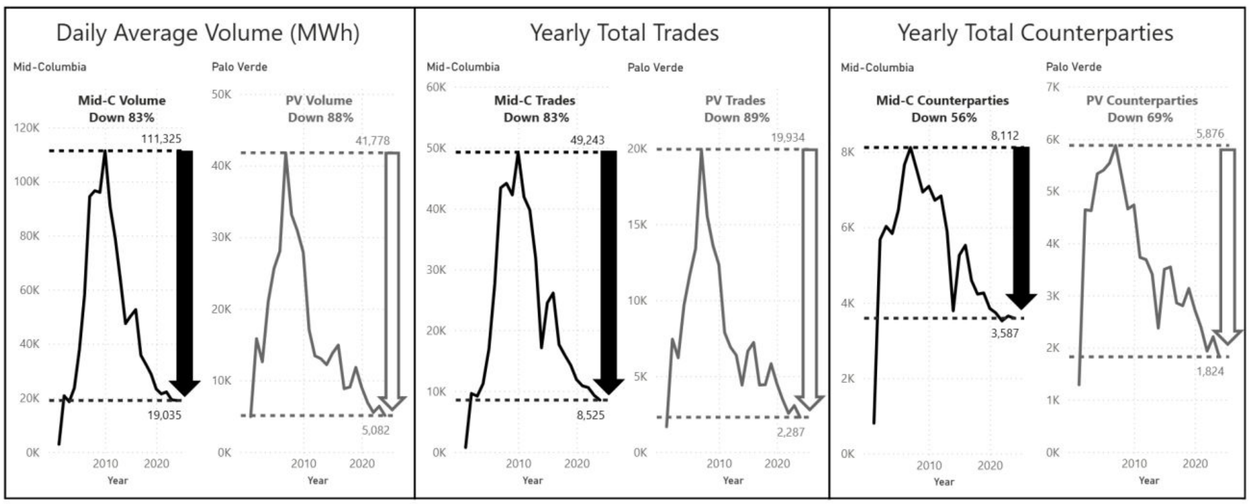
WECC bilateral market sales activity. Order PP 15-16. The Order postulates that widespread adoption of centralized, real-time energy imbalance markets, two day-ahead market constructs scheduled to go live in 2026, and the Southwestern Power Pool ("SPP") expansion into the Western Interconnection obviate the need for a soft price cap. The Order maintains that "[t]he Western market evolution thus provides meaningful alternatives to the traditional bilateral markets that are the subject of the soft price cap, and . . . market monitoring and mitigation in centralized markets also has a disciplining effect on associated bilateral markets." *Id.* P 16. The Commission contends that these new markets provide "meaningful alternatives to the traditional bilateral markets that are the subject of the soft price cap." *Id.*

While the Order is correct that Western energy markets have evolved since 2002, it does not follow that a soft price cap framework is no longer necessary. In fact, rather than address the problems that the soft price cap was intended to ameliorate, the markets developments invoked by the Order have led to growing illiquidity in the WECC bilateral markets. Since the California Independent System Operator Corporation ("CAISO") launched the Western Energy Imbalance Market ("WEIM") with PacifiCorp in 2014, WEIM has grown to twenty-two balancing areas, representing approximately 88 percent of United States ("U.S.") WECC load.[1/] Over the same period, liquidity in bilateral spot markets[2/] has declined sharply. The California Public Utilities Commission's Energy Division staff has observed that the Mid-Columbia ("Mid-C") and Palo Verde trading hubs can be very thinly traded with exceptionally low volumes and at higher prices than the CAISO market.[3/] Our own analysis of the data confirms this conclusion. Figure 1

1/ WECC load data from 2022 show that the twenty-two WEIM participating utilities had a combined annual load of approximately 650,800 TWh; this is approximately 88 percent of the U.S. WECC load in the same year.

2/ For purposes of these comments, the term "spot market" refers to the market for near-term, short-duration bilateral purchases of firm power at common trading hubs (*e.g.,* Mid-C or Palo Verde). We do not use "spot market" to refer to long-term bilateral purchases.

3/ See California Public Utilities Commission Energy Division Staff Comments on CAISO Annual Policy Initiatives Roadmap Process 2024 at 4, available at (below) shows that volume, number of trades, and counterparties—three different indicators of liquidity in the Western wholesale spot markets for next-day peak power contracts at the Palo Verde and Mid-C trading hubs—are down significantly from their highs. Trading volume (MWh) and the number of trades is down by over 80 percent for both Mid-C and Palo Verde, while the number of counterparties is down by 56 and 69 percent for Mid-C and Palo Verde, respectively.



Source: EIA Historical Wholesale Market Data, 2001 through 2024. Accessed, aggregated, and visualized by PG&E July 2025.
Available at https://www.eia.gov/electricity/wholesale/#history

Figure 1. Three metrics of liquidity in bilateral wholesale electricity markets from 2001 to 2024, specifically for on-peak next-day power contracts at Palo Verde and Mid-C hubs. These metrics demonstrate the declining liquidity of bilateral spot markets. Source: California LSEs' analysis using EIA data.

The decline is attributable to the fact that suppliers are bidding their surplus supply into the centralized markets instead of contracting bilaterally. While this may improve efficiency, it becomes problematic in times of tight system conditions, as recent experience demonstrates. For example, in 2020, there was a WECC-wide, record-setting heat wave. Given that most of the supply in WECC was participating in the WEIM, there were only a few suppliers available to bid into the bilateral spot markets. Elimination of the soft price cap could attract additional supply to

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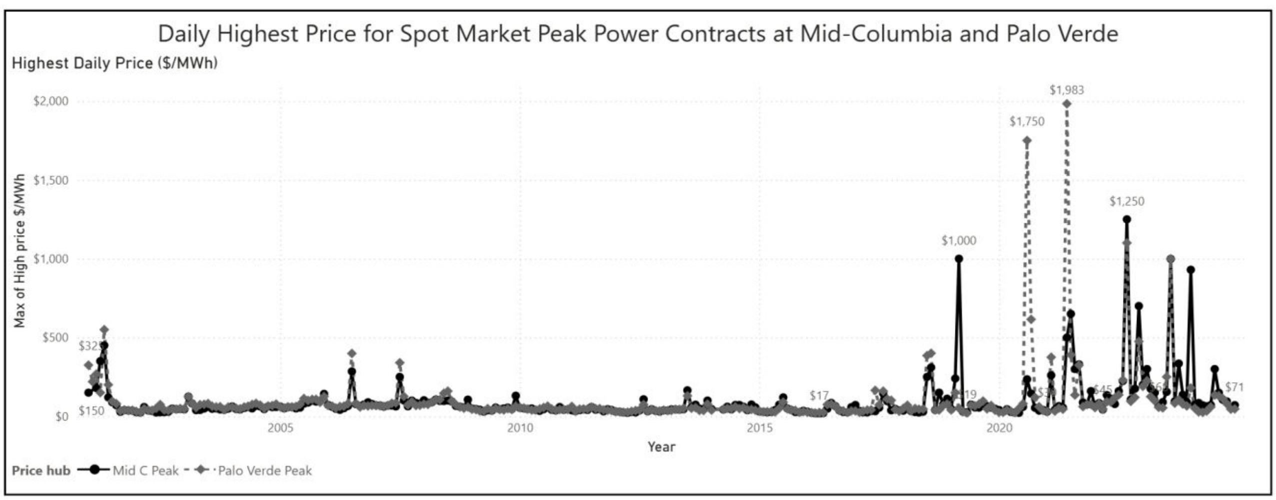
https://stakeholdercenter.caiso.com/InitiativeDocuments/CPUC-Hourly-Shaping-Factor-May-15-2024.pdf (download).

the bilateral spot markets in times of overall scarcity, but liquidity levels still may remain lower than necessary for effective price competition.

The expansion of WEIM and the WEIS market has thus made Western bilateral spot markets *more* volatile and susceptible to the exercise of market power.[4/] The smaller set of suppliers has more power to influence the bilateral index prices through just a few trades in a "thinly traded" market (*i.e.,* low volume, contracts, and counterparties). Figure 2 (below) shows the daily highest-priced contract prices for next-day peak power contracts at Mid-C and Palo Verde. The figure shows an increase in the frequency at which these indices reach or exceed $1,000/MWh, coincidental with the declining liquidity of these same markets. Accordingly, buyers opting to procure power to serve load on the bilateral market remain vulnerable to the exercise of market power by sellers in these markets, and accordingly could be compelled to pay unjust and unreasonable rates.



Source: EIA Historical Wholesale Market Data, 2001 through 2024. Accessed July 2025. Available at https://www.eia.gov/electricity/wholesale/#history

Figure 2. Daily highest price for spot market next-day peak power contracts at Mid-C and Palo Verde hubs. Source: California LSEs' analysis using EIA data.

The illiquidity in bilateral spot markets inevitably spills over into the markets operated by the CAISO, as FERC has previously recognized.[5/] To the extent the Order implicitly assumes

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4/ *Id.*

5/ 133 FERC ¶ 61,026; Order P 15.

interdependence is no longer an issue, the reasoning is faulty. Illiquidity in the WECC affects the day-ahead and real-time markets operated by the CAISO for two reasons. First, the CAISO's day-ahead and real-time markets use bilateral spot markets to inform certain market mechanisms as a proxy for the price of procuring daily capacity.[6/] There are no other substitute proxy prices to utilize in the market design. Second, for many resources, participation in the centralized market is voluntary. Some generators can choose to either sell their power in the markets operated by the CAISO or in bilateral markets and can toggle back and forth between the markets. The exercise of market power in bilateral spot markets, therefore, can (and in periods of tight supply, almost certainly will) affect market dynamics in the centralized markets, including leading to potential curtailment within the CAISO footprint. Removing the soft price cap in Western bilateral markets, combined with the illiquidity of the bilateral markets, could therefore lead to unjust and unreasonable rates and other public harms in the CAISO-operated markets.

Importantly, bilateral market liquidity is unlikely to improve in the near term. As the CAISO and SPP launch EDAM and the SPP Markets+ day-ahead markets, respectively, the California LSEs expect further reductions of available supply in bilateral spot markets, underscoring the need for protection against the exercise of market power in the bilateral spot markets.

Furthermore, even if the West ever reaches 100 percent participation in EDAM and Markets+, there is no guarantee that these markets will persist in complete coverage. Both EDAM and Markets+ markets are voluntary; participants can choose to leave the market at any

6/ For example, the Extended Day-Ahead Market's mechanism for curing failures of resource sufficiency evaluations is based on published bilateral index prices, *see* CAISO Pending Tariff § 33.11.2.1 (185 FERC ¶ 61,210; ER23-2686) (effective May 2026); similarly, the maximum import bid price is also based on published bilateral electric index prices, *see* CAISO Tariff § 30.7.12.5.3.

point. For instance, market design issues might drive participants back to bilateral spot markets; California's experience standing up a new market shows how difficult it can be.[7/]

It is possible, at some point, that nearly all supply in the West may be compelled to join an organized day-ahead and real-time market, effectively eliminating the need for bilateral spot markets. At that time, it is conceivable that the WECC soft price cap may become unnecessary to guard against unjust and unreasonable rates.[8/] Whether Western markets will ever achieve this level of participation remains to be seen. It is premature to eliminate the soft price cap until bilateral spot markets are no longer needed.

The Order simply ignores this reality. In light of declining liquidity in WECC Markets, which will not be solved in the near term, abandoning the soft price cap is imprudent.

B. An ex-ante price-disciplining mechanism is more effective at ensuring just and reasonable rates than ex-post enforcement.

The Order also contends that the soft price cap framework is no longer necessary because the Commission "has more robust legal authority and monitoring capabilities to address wholesale market misconduct" than existed in 2002. Order P 17. The Order cites the Energy Policy Act (EPA) of 2005 as an important check on potential market manipulation and explains that the Commission's Office of Enforcement "actively monitors wholesale market activity in WECC, including through ex post reporting of bilateral sales activity by jurisdictional sellers."

7/ California consumers had to experience a major energy crisis; endured the bankruptcies of its one-time market operator (the California Power Exchange Corporation) and one of the state's largest investor-owned utilities (PG&E); and experienced decades of litigation to address the upheaval caused by a flawed market design.

8/ Establishment of new markets is a necessary but not sufficient condition for market functionality. CAISO's EDAM and SPP's Markets+ represent a novel blend of open access transmission tariff and regional transmission organization ("RTO") elements. There are several new market mechanisms that need to be tested through real-world operation and experience. If these market designs prove to be flawed, both the price caps in CAISO's and SPP's centralized markets and the WECC soft price cap will be necessary to protect all wholesale customers.

Id. The Order asserts that the Commission is equipped to monitor and deter misconduct in the wholesale markets, rendering the soft price cap unnecessary.

The California LSEs agree that ex-post enforcement by the Commission is an essential component of ensuring just and reasonable rates. But the California LSEs disagree that the existence of this authority is itself sufficient to address market manipulation in Western energy markets for at least three reasons. First, ex-post proceedings to recover unjust rates are resource-intensive, disputatious, lengthy, and, even when ultimately successful, result in significant delay in refunding consumers. And, as the California energy crisis of 2000-2001 shows, in the event participants seek bankruptcy, the bankruptcy stay at a minimum prolongs the proceedings, and in many cases means that full reimbursement may not be available.

Second, the Order fails to appreciate the interdependency of Western markets and the implications of that interdependency for FERC's authority. As previously noted, the bilateral markets can have significant impacts on prices in the CAISO-operated markets, especially during times of scarcity. Bilateral trades that may later be found by FERC to be unjust or unreasonable would likely have the effect of increasing prices in the CAISO-operated markets (and could also lead to curtailments). The Commission may be able to correct the bilateral agreements, but it may be much more difficult, if not impossible, to undo the transactions settled in the CAISO-operated markets that were influenced by unjust and unreasonable rates in bilateral markets. If such a situation came to pass, the money lost, and the disruption caused by collateral impacts on centralized markets, could be substantial.

Finally, FERC's authority has not been tested in a true energy market crisis of the kind experienced in the early 2000s—and in any event, whether FERC's authority would be adequate in such a crisis (which may look different than the previous crisis) is unknown. The WECC soft price cap was an important, preventative measure put in place after the previous energy crisis. It would be imprudent to remove this critical prophylactic measure without offering any replacement. The concern is heightened given that the Commission proposes to do so in the midst of another Western energy market transition.

C. The minimal burden associated with the soft price cap is outweighed by its transparency benefits.

The Order also preliminarily concludes that the burden imposed on sellers by the soft price cap outweighs its benefits. The Order asserts that the filing burden of the price cap provides limited transparency benefits while imposing costs on market participants and the Commission and creating uncertainty for individual transactions. Order P 18. It is difficult to square the Order's preliminary conclusion with the D.C. Circuit's reasoning in *Shell*, which specifically called out the "important[]" transparency purposes the soft price cap serves for FERC. *Shell*, 107 F.4th at 992. But the court understated the transparency function of the soft price cap. To be sure, the soft price cap alerts FERC to above-cap sales that require additional analysis to determine if there is harm to the public interest. Commission enforcement staff reviewing high-price transactions benefit from availability of the cost justification information in the first instance. But the soft price cap also benefits market participants and the public, as this transparency-forcing function, and the attendant procedural mechanisms that attach to it, alerts a wide audience to high prices, provides justification information not otherwise available, and discourages entities from exercising market power or engaging in market manipulation—thus promoting just and reasonable rates. This public function is not always available when the Commission itself investigates ex post; the confidential nature of investigations initiated by the Commission precludes or delays public awareness of factors relevant to the Commission's exercise of its oversight responsibilities. If the Commission abandons the soft price cap, there are no equivalent transparency mechanisms that can serve the same function.

Moreover, costs imposed on market participants by the soft price cap are minimal. The filing requirement is only triggered by a limited number of transactions that occur infrequently. In fact, over the last twenty-three years that the soft price cap has been in place, the soft price cap has been exceeded on only a few occasions, demonstrating how few filings have been required; prior to 2020, sellers sought to recover payments above the soft price cap only once.[9/] Second,

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9/ In 2007, FERC rejected three cost justification filings as untimely. See 119 FERC while sellers must provide information in the justification filings, such as affidavits, purchase confirmations and invoices, this information is already within the seller's possession or control, minimizing their response burden.

As to Commission costs, the Commission has not substantiated that its review of justification filings is burdensome. The California LSEs submit that the burden of reviewing justification filings is minimal. In situations where FERC believes the *Mobile-Sierra* presumption may be rebutted, those situations should result in Commission investigation and incurrence of associated costs regardless of the existence of the soft price cap.

Finally, while the Order suggests that the filing requirement is burdensome because it creates uncertainty for individual spot market transactions while the filings are pending review at the Commission, Order P 18, this reasoning fails to consider that elimination of the soft price cap and filing requirement may instead create uncertainty for *all* spot market sales activity in WECC. Rather than establishing a transparent soft price cap and giving sellers an opportunity to mitigate any uncertainty for above-cap prices through their justification filings, FERC will instead provide no guidance at all as to what transactions may be subject to review. Absent the soft price cap and filing requirements, parties to a transaction would have to speculate as to whether FERC may open an investigation and whether a seller's justification, if required at some point in the future, may pass muster.

For all these reasons, the Order is incorrect that the filing burden imposed by the soft price cap outweighs its benefits.

IV. AN EX-ANTE PRICE DISCIPLINING MECHANISM REMAINS NECESSARY INTO THE FORESEEABLE FUTURE.

A. The soft price cap promotes just and reasonable rates.

Although the *Shell* decision overturned the refund orders challenged by sellers, nothing in the decision itself requires FERC to eliminate the soft price cap framework (as the Order

61,230 (2007). *See also* document number 20201007-5155 in FERC Docket No. ER21-57.

implicitly concedes). Nor does *Shell* suggest that the *Mobile-Sierra* presumption of reasonableness necessarily applies to all bilateral transactions under all circumstances. To the contrary, the *Shell* opinion reiterates the Commission's "statutory obligation to ensure that the ultimate rates are just and reasonable." *Shell*, 107 F.4th at 986-87.

Removing the soft price cap could wreak havoc in Western bilateral and organized markets during times of scarcity. Some suppliers in Western energy markets have the option to either bid into organized markets or offer into bilateral markets. This may include any supply within a Balancing Authority that has not yet chosen a Day-Ahead market, or supply from a Day-Ahead market participant that is considered "residual," "excess," or "voluntary."[10/] In times of tight supply, those suppliers will be incentivized to offer their power to bilateral spot markets to avoid the price cap in organized markets, and, given inelastic demand for power in tight conditions, can command nearly any price. In these conditions, a soft price cap serves as a blinking yellow light cautioning suppliers from setting prices without adequate justification, promoting just and reasonable rates in bilateral markets.

A soft price cap also promotes just and reasonable rates in organized markets like those run by the CAISO. If the Commission persists in removing the soft price cap, organized markets like those operated by the CAISO will have to compete for that supply by offering scarcity pricing (effectively offering a premium) to bid into the organized market. If buyers in organized markets are successful in obtaining that supply, they may do so but via rates that may not be just and reasonable. If buyers in organized markets are *not* successful in obtaining that supply because of the price cap, there may be scarcity or even load curtailments. Because Western energy markets will remain a mix of bilateral trades and voluntary, organized markets for the

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10/ For example, under EDAM, an entity is required to offer into the market only enough supply to cover its 1) Load Forecast +; 2) Imbalance Reserves; 3) Flexibility Requirements; 4) Ancillary Services, and 5) Reliability Capacity Bidding. Those combine to form the EDAM Resource Sufficiency Evaluation Obligation. If an entity has any additional supply above that threshold, it could sell that additional supply in the bilateral market.

foreseeable future, in the event of scarcity (whether driven by extreme weather or other disruptions), load-serving entities participating in the CAISO-operated markets will effectively be punished for being in an organized market with a price cap.

B. Even if the Commission abandons the soft price cap framework, it should not do so until new Western energy market frameworks have matured.

As the Order recognizes, significant market changes are underway in Western energy markets, including EDAM, Markets+, and the Western Resource Adequacy Program. Western markets have not achieved the level of participation necessary to consider abandoning the soft price cap. These markets need to have secured commitments from all (or at least most) of the Balancing Authorities in the West, and all of those Balancing Authorities need to be on-boarded. This process is underway, but it is far from complete. Not only are these developing markets still nascent, but they are also voluntary. Should a participant of EDAM, WEIM, or SPP Markets+ find it more lucrative to opt out of the market, even temporarily, to take advantage of bilateral markets without a price cap, that participant would have effectively circumvented the market power mitigation rules that the Order claims have removed the need for a West-wide cap.

Furthermore, market mechanisms designed to prevent the exercise of market power during scarcity conditions will necessarily need to be stress-tested by real world events that by their very nature are unpredictable and may occur infrequently. Removing the soft price cap framework may be warranted once anticipated Western markets have been successfully introduced and have stabilized, but that point has not yet arrived. Simply abandoning the soft price cap without additional deterrents to market misconduct would be a costly mistake.

V. THE COMMISSION NEEDS TO DEVELOP A ROBUST, ACCURATE RECORD BEFORE DECIDING NEXT STEPS ON THE SOFT PRICE CAP.

The Order is based on a significant number of factual issues that have not been developed and, as explained above, are demonstrably incorrect. Without an adequate record and an opportunity for interested participants to be heard on the factual bases sustaining the Order, the Commission risks making an arbitrary and capricious decision. *See Fed. Comm. Comm'n v. Fox Television Stations*, 556 U.S. 502, 515 (2009) (when an agency's new policy rests upon factual findings that contradict those which underlay its prior policy, it must provide a more detailed justification than what would suffice for a new policy created on a blank slate). In light of the Commission's prior findings justifying the soft price cap and recognizing the interconnection between Western bilateral spot markets and organized markets, reasoned decision-making regarding the soft cap requires additional factfinding.

Additional investigation could take many forms—e.g., a technical conference or a paper hearing. When conducting such fact-finding, the Commission should not limit itself to considering only the binary question of whether to retain or abandon the current soft cap framework. The Commission should also, at a minimum: conduct a historical review of the price disciplining effect of the current soft price cap; analyze of the potential outcomes for various market participants and consumers in the event of modifications or removal of the soft price cap; consider the sufficiency of current enforcement mechanisms (especially in the event of periods of tight supply); and investigate the presumptive market conditions under which "the *Mobile-Sierra* presumption should not apply at all . . ." to bilateral transactions. *Shell*, 107 F.4th at 992.

VI. CONCLUSION

For the foregoing reasons, the California LSEs respectfully request that the Commission (1) retain the existing soft price cap framework for the foreseeable future; and (2) further investigate the factual bases and justifications for any potential Commission action on the soft price cap.

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Respectfully Submitted on Behalf of,

JONTHAN J. NEWLANDER

By: /s/ Jonthan J. Newlander
JONTHAN J. NEWLANDER
SAN DIEGO GAS & ELECTRIC COMPANY
8330 Century Park Court, CP32D
San Diego, California 92123
Telephone: (858) 654-1652
E-Mail: jnewlander@sdge.com
Attorney for
SAN DIEGO GAS & ELECTRIC COMPANY

MICHELLE MELTON
NOELLE R. FORMOSA

By: /s/ Michelle Melton
MICHELLE MELTON
PACIFIC GAS AND ELECTRIC COMPANY
Law Department, 19th Floor
300 Lakeside Drive, Suite 210
Oakland, CA 94105
Telephone: (925) 220-0293
Facsimile: (510) 898-9696
E-Mail: Michelle.Melton@pge.com
Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

KATY MORSONY

By: /s/ Katy Morsony
KATY MORSONY
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
Senior Counsel and Manager of Strategic Policy Initiatives
Attorney for
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

REBECCA FURMAN

By: /s/ Rebecca Furman
REBECCA FURMAN
SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-3475
E-mail: Rebecca.Furman@sce.com
Attorney for
SOUTHERN CALIFORNIA EDISON COMPANY

LISA G. DOWDEN
JEFFREY M. BAYNE
AMANDA C. DRENNEN
SAMUEL B. WHILLANS

By: */s/ Amanda C. Drennen*
AMANDA C. DRENNEN
Spiegel & McDiarmid LLP
1818 N Street, NW
8th Floor
Washington, DC 20036
Telephone: (202) 879-4000

JANE LUCKHARDT
General Counsel
Northern California Power Agency
651 Commerce Drive
Roseville, CA 95678
Telephone: (916) 781-4200
E-Mail: jane.luckhardt@ncpa.com
Attorneys for
NORTHERN CALIFORNIA POWER AGENCY

BONNIE S. BLAIR
MARGARET E. MCNAUL
NICKOLAS H. BARBER

By: */s/ BONNIE S. BLAIR*
BONNIE S. BLAIR
Thompson Coburn LLP
1909 K Street, N.W. Suite 600
Washington, D.C. 20006-1167
202.585.6900
E-Mail: bblair@thompsoncoburn.com
mmcnaul@thompsoncoburn.com
nbarber@thompsoncoburn.com
Attorneys for
THE CITIES OF ANAHEIM, AZUSA, BANNING, COLTON, PASADENA, AND RIVERSIDE, CALIFORNIA

Dated: August 14, 2025

CERTIFICATE OF SERVICE

I hereby certify that I have on this day caused the foregoing document to be served upon all parties designated on the official service list in this proceeding in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure.

Dated at Oakland, California this 14th day of August 2025.

/s/ Tauvela V. U'u
TAUVELA V. U'U
PACIFIC GAS AND ELECTRIC COMPANY
300 Lakeside Drive, 19th floor
Oakland, CA 94612

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

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Willie Calvin,
Regulatory Case Manager

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

August 14, 2025

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SUMMARY OF RECOMMENDATIONS[1]

CalCCA recommends the following with respect to the PD:

- The PD's closure of the proceeding should be rejected, and instead the Commission should open a new track to ensure compliance with Public Utilities Code section 366.2(c)(9) regarding ensuring IOUs provide customer data to CCAs, and sections 1701.1 and 1701.5 regarding addressing all scoped issues in the timeframe established in the Scoping Memo including:
  - Identifying and establishing the processes and requirements for IOUs to provide all data, accurately and consistently, to allow CCAs to offer dynamic pricing to unbundled customers; and
  - Establishing the additional systems and processes allowing CCAs to participate in the calculation and billing for dynamic rates;
  - Discussing results from mid-term and final RTP pilot evaluations and identifying updates based on results;
- The PD's requirement that IOUs provide detailed descriptions in their DF Rate Proposals regarding their planned collaboration with CCAs on various features of DF rates and DF rate programs should be adopted and amended to include details regarding CCA system integration and ASP coordination; and
- The PD's rate design guidance for both LSEs and IOUs should be adopted, while additional components are developed for systems and processes and as a result of learnings from the expanded pilots.

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION

The California Community Choice Association[2] (CalCCA) submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[3] on the proposed *Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals*[4] (PD), dated July 25, 2025.

I. INTRODUCTION

The PD adopts guidelines for investor-owned utilities (IOU) for demand flexibility (DF) rate design proposals (DF Rate Proposals), which will allow the IOUs to implement DF rates as a tool for achieving load shifting. The PD, however, closes the proceeding without addressing scoped issues 4, 5, and 6, related to systems and processes to enable access to dynamic rates, Commission support on implementing the California Energy Commission (CEC) Load Management Standards (LMS),[5] or evaluation or expansion of the existing dynamic rate pilots. As a result, CalCCA provides the following comments and requested modifications on the PD.

First, the PD fails to proceed in the manner required by law by prematurely closing the proceeding without addressing scoped issues that will allow unbundled customers to participate in dynamic pricing. While the PD does address unbundled customers and dynamic pricing rate design, it fails to resolve scoped systems and processes issues, including CCA data access, and cost responsibility surrounding those systems and processes. This failure to resolve scoped issues prejudices CCAs by failing to provide what is necessary to allow unbundled customers to benefit from DF. Closing the proceeding prematurely also fails to allow the incorporation of learnings

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

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

[4] [Proposed] *Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals*, Rulemaking (R.) 22-07-005 (July 25, 2025).

[5] Title 20, California Code of Regulations (CCR) § 1623 *et seq.*

from the pilots which must be considered in the context of rate design, and systems and processes for implementation. Instead, the PD should open a new track to address these issues.

Second, the PD's requirement that IOU DF Rate Proposals incorporate a plan on collaboration with the CCAs regarding DF rate features and programs should be adopted. This requirement should be expanded to require the IOUs to include a description of how CCAs will interact with the IOU systems enabling DF rates, and how the IOUs will share information with CCAs and customers regarding automated service providers (ASPs) access.

Finally, the Commission should adopt the PD's rate design guidance to enable LSE participation in DF rate programs, but should acknowledge that the findings do not address how unbundled dynamic generation rates will be implemented. This implementation should occur through the systems and processes described in scoped item 4. In addition, the PD's guidance for IOU rate design proposals is appropriate as interim guidance, but should eventually incorporate learnings from the expanded pilots, as well as features necessary to interact with adopted systems and processes.

CalCCA recommends the following with respect to the PD:

- The PD's closure of the proceeding should be rejected, and instead the Commission should open a new track to ensure compliance with Public Utilities Code section 366.2(c)(9)[6] regarding ensuring IOUs provide customer data to CCAs, and sections 1701.1 and 1701.5 regarding addressing all scoped issues in the timeframe established in the Scoping Memo including:
    - Identifying and establishing the processes and requirements for IOUs to provide all data, accurately and consistently, to allow CCAs to offer dynamic pricing to unbundled customers; and
    - Establishing the additional systems and processes allowing CCAs to participate in the calculation and billing for dynamic rates;
    - Discussing results from mid-term and final RTP pilot evaluations and identifying updates based on results;
- The PD's requirement that IOUs provide detailed descriptions in their DF Rate Proposals regarding their planned collaboration with CCAs on various features of DF rates and DF rate programs should be adopted and amended to include details regarding CCA system integration and ASP coordination; and
- The PD's rate design guidance for both LSEs and IOUs should be adopted, while additional components are developed for systems and processes and as a result of learnings from the expanded pilots.

6 All section references herein are to the Public Utilities Code, unless otherwise stated.

II. BACKGROUND

California's pursuit of load shifting through DF rates is in flux. The state's interest in dynamic pricing stems from persistent challenges like high summer peak loads that threaten reliability, as well as ensuring affordability in the face of large rate increases. While both the Commission and the CEC are working to advance load shifting through dynamic pricing mandates, pilots, and other programs, many of the core elements of these programs remain in development, leaving key design, implementation, and participation details unsettled.

A. CEC LMS

The CEC's January 2023 amendments to the Load Management Standards (LMS), require Large IOUs, Large CCAs, and Large publicly owned utilities (POU) to offer hourly or sub-hourly dynamic rates or programs by 2027.[7] LMS implementation includes five overall elements: (1) marginal cost-based rates and/or programs; (2) the Market Informed Demand Automation Service (MIDAS) to hold LSE time-dependent rates; (3) the Single Statewide Tool (SST) to allow third parties to access customer rate information; (4) public information programs to ensure customers understand the dynamic pricing offerings; and (5) LSE compliance plans to explain compliance with the various requirements.[8] Although the IOUs, CCAs, and POUs continue to comply with the timeframes for completion of the LMS elements, every category is still under construction: the SST is not yet complete, many compliance plans remain under review, dynamic hourly rates are still in pilot testing, and the CEC continues its improvements to MIDAS. The CEC stated in the early stages of the LMS rulemaking that CCAs as providers of electric service to a large sector of California electric customers need to be part of LMS to ensure its overall effectiveness:

> The Warren-Alquist Act was adopted prior to the creation of CCAs, however CCAs function within the service territory of IOUs. The load management standards apply to electric utility service territories, which include customers served by CCAs that operate within the service territory of IOUs. ***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 increasing rapidly, any other***

[7] Title 20, CCR §§ 1623(d)(2), 1623.1(b)(4). Note that while LMS requires CCAs to offer dynamic rates or programs by 2027, CCA governing boards have sole authority over the rates that they adopt.

[8] *Id.* § 1621(c)(8), (9), and (10) (MIDAS), § 1632(c)(2)(A) (SST), § 1632.1(b)(5) (public information programs), §§ 1621(d)(1), 1623.1(a)(1)(C) (LMS compliance plans).

> ***interpretation would diminish the effectiveness of the load management standards and defeat the purpose of the statute***.[9]

Despite CCAs being targeted as essential to meeting statewide DF goals, the tools and processes needed for their full participation in the LMS are still largely not available.

B. R.22-07-005

Soon after the opening of the LMS rulemaking, the Commission opened this proceeding in July of 2022 to enable DF through electric rates and to discuss the implementation of the income-graduated fixed charge (IGFC) ordered by Assembly Bill 205. The Order Instituting Rulemaking (OIR) advances six objectives, the last of which is to "enable participation in demand flexibility by both bundled ***and unbundled customers***."[10] The Scoping Memo reinforces this objective, scoping in two questions regarding unbundled customers.[11] First, the Scoping Memo addresses how DF rate design can ensure that unbundled customers can participate:

> Track B Scoping Issue 3.e: How should demand flexibility rates be designed to enable ***all load serving entities*** to have the option to participate?

Second, the Scoping Memo addresses what systems and processes are necessary to ensure both bundled and unbundled customers have access to those prices:

> Track B Scoping Issue 4: How should the Commission ensure access to dynamic electricity prices by bundled ***and unbundled customers***, devices, distributed energy resources, and third-party service providers? What systems and processes should the Commission authorize for access to prices and responding to price signals?
>
> a. What systems and processes should the Commission authorize for computation of dynamic prices for bundled ***and unbundled customers***?
>
> b. What systems and processes should the Commission authorize to enable load serving entities to offer ***unbundled customers*** the option to take service on dynamic electricity prices?
>
> c. What ***systems and processes*** should the Commission authorize to enable third-party service providers (e.g., automation service

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[9] CEC Docket 19-OIR-01, *Draft Staff Analysis of Potential Amendments to the Load Management Standards* (Mar. 23, 2021), at 19 (emphasis added).

[10] *Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates*, R.22-07-005 (July 14, 2022) (OIR), at 1 (emphasis added).

[11] *Assigned Commissioner's Phase 1 Scoping Memo and Ruling*, R.22-07-005 (Nov. 2, 2022) (Scoping Memo).

> providers, device manufacturers) to offer demand flexibility services to customers?
>
> d. What ***systems and processes*** should the Commission authorize to enable customers to optimize and pre-schedule their energy use to provide demand flexibility (e.g., forward transactions)?
>
> e. What are the ***costs*** associated with these systems and processes (for access to prices and responding to price signals), and how should these costs be recovered?
>
> f. How should these ***systems and processes*** (for access to prices and responding to price signals) be ***managed and overseen*** (e.g., utility administration or third-party administration)?

In addition, the Scoping Memo addresses the need to support the implementation of LMS:

> Track B Scoping Issue 3.f: How should demand flexibility rates be designed to comply with the California Energy Commission's amendments to the Load Management Standards?
>
> Track B Scoping Issue 5: How should the Commission support the implementation of the amendments to the California Energy Commission's Load Management Standards?

The Scoping Memo splits the proceeding into two Tracks – Track A addresses the IGFC, and Track B addresses the DF rate design (through Working Group (WG) 1) and systems and processes (through WG 2)).

1. Working Group 1

WG1 discussed updates to the Commission's existing Electric Rate Design Principles and new Demand Flexibility Design Principles (DFRP), which the Commission formalized in Decision (D.) 23-04-040. These principles guide the development of DF rates and incorporate enabling bundled and unbundled customer access to DF rates. DFRP 4 states: "The systems and processes for calculating dynamic price signals should include bundled ***and unbundled rate components so that any load serving entity can elect to participate.***"[12] CalCCA participated in WG 1 meetings to ensure unbundled customer interests were represented during the rate design discussions. CalCCA also provided input on rate design into the WG Report and provided comments on the Report.[13]

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[12] D.23-04-040, *Decision Adopting Electric Rate Design Principles and Demand Flexibility Design Principles*, R.22-07-005 (Apr. 27, 2023), at 3 (emphasis added).

[13] *California Community Choice Association's Comments on Track B Working Group Report*, R.22-07-005 (Nov. 13, 2023), at 5 (summarizing CalCCA's positions on WG 1 Proposals).

2. Working Group 2

WG 2 addressed the systems and processes for access to prices and responding to price signals. CalCCA and member CCA staff participated to inform the development of systems and processes for enabling DF rates, which included presentations on barriers for CCA unbundled customer participation in dynamic pricing. Chief among the barriers identified are data access and data quality. CalCCA and its member CCAs participated in multiple meetings with each IOU and Energy Division Staff to discuss the barriers.[14] CalCCA's comments in the WG Report section on Questions 4b and 4e regarding CCA enablement detailed the different states of data access across IOU service areas for PG&E, SCE, and SDG&E.[15] These comments primarily focused on the data necessary for enabling CCAs to develop and implement their own DF rates: hourly or sub-hourly interval data, both billing-quality and non-billing-quality.

3. Ongoing Data Access and Quality Issues

In the intervening 22 months, each IOU has worked with CCAs to improve access to these data; however, issues remain. These issues include both access to data and quality of data. Regarding access, SCE and SDG&E provide hourly, billing-quality data for all customers to the CCAs in their service area approximately 30 days after power flow; however, PG&E does not. PG&E claims that it cannot provide this data fully until its Billing Modernization Initiative (BMI)[16] is complete in 2029. However, PG&E has offered to provide hourly, billing-quality interval data for up to 600,000 accounts and possibly more if CCAs request the data. Currently, PG&E only provides this type of data for customers on Net Billing Tariff (NBT) and those participating in the expanded RTP pilots. Of the billing-quality interval data PG&E is providing related to the expanded RTP pilots, CCAs are receiving data for only some of their customers participating in the pilots. This remains a significant impediment to the CCAs in PG&E's service area due to the reliance on this billing-quality data for developing DF rates.

In terms of quality, CCAs are experiencing data quality issues in all IOU service areas related to both billing-quality and non-billing quality Advanced Metering Infrastructure (AMI) data. AMI data is needed for implementing DF rates for forecasting and load management. Billing-

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14 *Id.* at 5, n.4 (describing the meetings on barriers between the CCAs, IOUs, and Energy Division).

15 *Id*. at 11-22.

16 *See* Working Group Report, R.22-07-005 (Oct. 11, 2023), at 233-234 (PG&E's proposal for addressing billing usage data access barrier stating that the long-term solution is part of PG&E's billing system upgrade); *see also Application of Pacific Gas and Electric Company (U 39 M) for Approval of Its Billing Modernization Initiative,* Application (A.) 24-10-014 (Oct. 23, 2024).

quality data takes more time to process and, therefore, is shared with more delay than non-billing-quality data. SCE's Snowflake platform provides AMI data within two days of power flow to a customer; however, issues exist with the volatility and accuracy of data sets. SDG&E's data lake solution provides SDG&E CCAs with AMI data within three days of power flow, but CCAs are required to pull the most recent seven days of complete data each call, rather than pulling deltas day over day. SDG&E's AMI data has inconsistencies in large counts of meters with daily sum usage of zero values, and clarity issues continue with data quality metrics.

Currently, CCAs across IOU service areas are not on equal footing, with some having better access to data than others. In addition to inequitable access, data quality is also an issue due to the differing data platforms used by the IOUs. While CalCCA and its members appreciate the work and collaboration by the IOUs, the Commission still has an obligation to provide directives to the IOUs to establish universal standards for data provision and troubleshooting.

C. Commission Proceedings Addressing CCA Overall Data Access Needs Outside of Dynamic Pricing

CCA data access issues are significant, especially for CCAs in PG&E service area. Other pending Commission proceedings are considering these data access issues, but none are considering them for the purpose of CCAs being able to offer dynamic pricing. Indeed, ***this proceeding*** is the appropriate place to address that issue. As an example of another proceeding addressing CCA data access issues, the Scoping Memo in the Distributed Energy Resources (DER) proceeding, R.22-11-013, asks what rules and requirements the Commission should develop or modify to improve data access to support utilization of DERs and to align with the DF OIR and High DER Future Grid OIR.[17] CCAs have provided input regarding interval data in the DER Data Working Group as they did in the DF WG Report, but there is no certainty that solutions will be developed based on that input or by when. Based on the Data Working Group's launch in September 2024 and the original scope of the proceeding, a PD in R.22-11-013 addressing Data Working Group recommendations may not be issued until April or May of 2026, which would further delay CCA ability to support the implementation of DF rates. And, as stated above, the data access issues being addressed in the DER proceeding relate primarily to support DER utilization. Again, ***this proceeding*** should address data access related to dynamic pricing.

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[17] *Assigned Commissioner's Scoping Memo and Ruling,* R.22-11-013 (May 31, 2023), at 3.

Similarly, the Joint PG&E CCAs introduced the need for access to hourly, billing-quality interval data in PG&E's Billing Modernization Initiative (BMI) application.[18] Even if the Commission orders PG&E to provide that data to CCAs in its territory based on the BMI application, that would only address the issue for one IOU and would not occur until the end of 2029. The DF proceeding is the ***only proceeding*** explicitly scoped to resolve this barrier to accessing data to enable DF rates and to do so in time for LMS compliance.

D. CCA Participation in Real-Time Pricing Pilots

The real-time pricing (RTP) pilots testing DF rates are also ongoing and rely on CCA involvement. Soon after the Commission published the WG Report, the Commission issued D.24-01-032 to expand the RTP pilots being implemented by PG&E, Valley Clean Energy (VCE) (a CCA located in PG&E's service territory), and SCE. The Energy Division Staff Proposal that informs D.24-01-032 asserts that pilot expansion will help IOUs ***and*** CCAs "gain important operational experience in offering dynamic rates to customers across different applications and capabilities," for complying with LMS.[19] Decision 24-01-032 also includes pilot evaluation provisions stipulating that PG&E and SCE shall submit mid-term and final evaluations by August 1, 2026, and March 1, 2028, respectively.[20] As with any evaluation, the results are important for potential pivoting of pilot implementation and for informing future program and rate design by the Commission. With the pilot mid-term and final evaluations outstanding, and other DF elements in flux including systems and processes necessary for CCA participation in DF related to data unresolved, many of the scoped items in this proceeding have not been addressed. As a result, this DF proceeding should not be closed as set forth in the PD. Instead, a separate track should be established to address necessary changes to DF rate structure based on pilot learnings and the data access and systems and processes issues.

III. THE PD FAILS TO PROCEED IN THE MANNER REQUIRED BY LAW BY PREMATURELY CLOSING THE PROCEEDING

The PD fails to proceed in the manner required by law by prematurely closing the proceeding without addressing scoped items that will allow unbundled customers to participate in dynamic pricing. While the PD does address unbundled customers and dynamic pricing rate

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18 *See Prepared Direct Testimony of Kyra J. Coyle on Behalf of The Joint Community Choice Aggregators in PG&E's Billing Modernization Initiative*, A.24-10-014 (June 30, 2025), at 49, Table 6.

19 *Staff Proposal on Existing Dynamic Rate Pilot Expansion in Demand Flexibility Rulemaking (R.22-07-005)*, R.22-07-005 (Aug. 15, 2023), at 2 (listing the second benefit of expanding the pilots).

20 D.24-01-032, at 82, COL 37.

design, it fails to resolve scoped systems and processes issues, including CCA data access, and cost responsibility surrounding those systems and processes. Closing the proceeding prematurely also fails to allow the incorporation of learnings from the expanded pilots which must be considered in the context of rate design, and the systems and processes for implementation.

As set forth in more detail below, closing the proceeding will result in the Commission failing to proceed in the manner required by law in at least two ways. First, failing to address scoped issues violates sections 1701.1 and 1705.1 requiring the Commission to issue a Scoping Memo describing the issues to be addressed, and to resolve those issues within the timeframe set forth in the Scoping Memo. Here, the Commission scoped the development of the systems and processes to enable unbundled customer participation in dynamic pricing into the proceeding, which has not been resolved. Second, section 366.2 requires the Commission to ensure CCA access to customer data, which it has failed to do here despite the Commission and parties extensively addressing the issue throughout the proceeding. Despite promising in the PD that "[t]he Commission will address these issues in one or more new rulemakings," the failure to address the scoped issues in ***this*** proceeding will result in the Commission failing to proceed in the manner required by law. As a result, the Commission should keep the proceeding open and establish a track and timetable to address these systems and processes issues.

A. The PD's Failure to Resolve Scoped Issues Prior to Closing the Proceeding Violates Sections 1701.1 and 1701.5 and Prejudices Unbundled Customers

The PD's failure to resolve scoped issues prior to closing the proceeding violates sections 1701.1, and 1701.5, to the detriment of CCAs and their unbundled customers. Section 1701.1(b)(1) requires the assigned commissioner to "issue by order or ruling ***a scoping memo that describes the issues to be considered and the applicable timetable for resolution*** . . . ." Section 1701.5 states that the Commission "***shall*** resolve the issues raised in the scoping memo within 18 months of the date the proceeding is initiated . . . ."[21] If the Commission is not able to meet that deadline, section 1701.5 requires it to "make[] a written determination that the deadline cannot be met, including findings as to the reason, and issue[] an order extending the deadline."[22] Here, the Commission noted in the Scoping Memo its intent to complete the proceeding in 24 months "[d]ue to the complexity and number of issues in this proceeding."[23] In addition, Rule

21 Section 1701.5(a).
22 *Ibid.*
23 *Scoping Memo,* at 10.

7.3 of the Commission's Rules require the issuance of a "scoping memo for the proceeding, which shall determine the schedule . . ., ***issues to be addressed,*** and need for hearing."

As noted in caselaw interpreting these scoping memo requirements, "[i]dentifying the issues under consideration facilitates informed participation—including presentation of arguments and evidence—by those who may have a stake in the resolution of those issues."[24] The court went on to state that "[i]f the Commission cannot fairly be said to have complied with the statutory scoping memo requirement, it has failed to regularly pursue its authority."[25] Therefore, if the Commission fails to consider scoped issues, and the deviation from the Scoping Memo causes prejudice, a court will reverse the Commission's actions.[26]

1. The Commission Failed to Address Scoped Issues

The Commission failed to address scoped issues prior to closing the proceeding in violation of sections 1701.1 and 1701.5. As noted above in Section II.B., the Scoping Memo specifically asks how the Commission can ensure access to dynamic electricity prices by unbundled customers, what systems and processes need to be authorized for access to those prices, and how unbundled customers can be enabled to take service on dynamic prices.[27] It is these scoped issues, regarding systems and processes (and the costs associated with those systems) necessary for the Commission to adopt to ensure LSEs can implement dynamic rates to their unbundled customers, that the Commission ***fails to resolve*** in the PD or in the proceeding. In many cases in which courts side with the Commission regarding whether a Decision departs from the Scoping Memo, the court finds that an issue raised by the petitioner was not explicitly included or excluded from the scoped issues. Early in this proceeding, the Commission explicitly acknowledged that the systems and processes contemplated in the Scoping Memo include issues regarding CCA access to data from the IOUs for billing related to dynamic pricing:

> CalCCA proposed to specify that the systems and processes necessary for CCAs to participate in demand flexibility and dynamic pricing include (i) CCA access to data from IOUs for the timely receipt of billing quality interval data to view CCA load, and (ii)

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24 *Golden State Water Co. v. Public Utils. Comm'n* (2024) 15 Cal.5th 380, 394-395.

25 *Ibid.*

26 *See Southern California Edison Co. v. Pub. Utils. Comm'n* (2006) 140 Cal.App.4th 1085, at 1106-07 (Commission's failure to comply with its scoping memo constitutes reversible error if the failure to do so was prejudicial); *see also Bullseye Telecom, Inc. v. California Pub. Utils. Comm'n* (2021) 66 Cal.App.5th 301, 324 (even if the Commission deviates from the Scoping Memo, petitioner must show that the deviation was significant or that it was prejudiced by it).

27 Scoping Memo, at 5.

> upgrades to IOU systems to incorporate billing and settlement of the dynamic rates for CCA customers. Cal Advocates and PG&E responded by pointing out that the scoping memo for this proceeding anticipates for a working group to develop a proposal to address this issue. We agree that the question of which systems and processes are needed to enable unbundled customers to participate in demand flexibility and dynamic pricing will be addressed through the working group proposal process described in the scoping memo.[28]

Therefore, the Commission found that:

> It is reasonable for the Commission to adopt the following as Demand Flexibility Design Principle 4: The systems and processes for calculating dynamic price signals should be able to include bundled and unbundled rate components so that any load serving entity can elect to participate.[29]

It is clear that the Commission considers CCA data access to be within scope of this proceeding. The Commission also acknowledges in the PD that "[t]his decision closes R.22-07-005 ***without resolving remaining Phase 1 scoping issues of this proceeding, which include . . . Track B, Working Group 2 Issues 4, 5, and 6 that relate to systems and processes to enable access to dynamic rates . . . .***"[30] As noted below, this failure to resolve key issues is detrimental to CCAs and their customers.

2. CCAs are Prejudiced by the Commission's Failure to Address Scoped Issues

CCAs are prejudiced by the Commission's failure to address scoped issues. CalCCA has been an active participant from the beginning of this proceeding, after the Commission "encouraged" "a]ll [CCAs] to participate in this proceeding in the OIR."[31] At its first opportunity in Comments on the OIR, CalCCA commented that:

> Effective operation of demand flexibility tools requires timely access to usage data. While the IOUs presumably have real-time access, ***CCAs . . . depend on the IOU billing systems to obtain data necessary to compute bills for their customers.*** Today, however, data accessibility varies by utility and is insufficient to meet CCAs' needs; the Commission should set standards for data quality and accessibility across all IOU territories to help ensure that all

[28] D.23-04-040, *Decision Adopting Electric Rate Design Principles and Demand Flexibility Design Principles,* R.22-07-005 (May 3, 2023), at 30-31 (citing CalCCA, Cal Advocates, and PG&E Comments).
[29] *Id.* at 31.
[30] PD, at 11 (emphasis added).
[31] *See* OIR, at 11.

> providers can offer effective dynamic rate options to their customers. ***The lack of access to real-time usage data is a barrier to CCAs being able to offer the kinds of expanded demand flexibility tools to customers contemplated by this proceeding. Without addressing this asymmetry in data access, the Commission would inadvertently prevent the majority of customers from being able to contribute to meeting statewide goals.***[32]

Indeed, in Working Group 2, CalCCA presented and commented extensively on these needs. Energy Division and the IOUs also met with CalCCA on a number of occasions to address these data access barriers. All three IOUs worked to improve the data access issues, but as noted above in Section II.B.3., issues remain. Also not resolved are the additional systems and processes needed to compute the different components of dynamic pricing, which has been contemplated in both this proceeding and in LMS.[33] While the IOUs move ahead with rate design and their own systems which can presumably interface with their billing systems, the CCAs will face barriers when implementing dynamic pricing without having timely and accurate data bill for those rates.

The Commission should in this proceeding resolve the data access and accuracy problems to ensure unbundled customers can access dynamic rates on an equal footing as bundled customers. Moreover, the Commission should address the systems and processes necessary for computing rates, and how the costs associated with the systems and processes developed for accessing prices and responding to price signals should be recovered. The Commission's failure to address these issues prior to closing the proceeding prejudices CCAs and their customers.

B. Failing to Resolve Data Access Issues for CCA Unbundled Customers to Access Dynamic Pricing Violates Section 366.2's Requirement that the Commission Ensure CCA Access to Customer Data

The Commission's failure to address the data access and accuracy issues in the context of dynamic pricing also violates the Commission's duty under section 366.2(c)(9) to ensure IOUs provide to CCAs necessary billing and electrical load data, including electrical consumption data, for CCAs to offer dynamic pricing. As set forth above in Section II.B.3, CCAs either are not receiving the data for their customers or accuracy and latency issues persist. In D.04-12-046, the

32 *CalCCA's Comments on Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates,* R.22-07-005 (Aug. 15, 2022), at 2 (citations omitted; emphasis added).

33 The Working Group Report recommends a "price machine" as proposed by Energy Division, which CalCCA supported. In LMS, both MIDAS and the SST address components of providing rates, but don't resolve all issues. The SST is also yet to be approved by the CEC or implemented.

Commission stated that section 366.2(c)(9) "does not permit the [IOUs] to deny CCAs access to relevant customer or load information, and that "the plain language of the law means that the CCA is entitled to any and all billing data that is reasonably useful to the CCA."[34] Here, CCAs cannot bill for dynamic rates without the necessary accurate customer data, received on a regular basis. The Commission should therefore enforce section 366.2(c)(9) by ensuring CCAs have access to accurate and timely data to provide dynamic pricing.

As noted above, while SCE and SDG&E have platforms to provide the data, the timing, quality, and consistency of those systems are still in flux. In addition, while PG&E has committed to providing hourly interval data for CCA customers on an interim basis until its new billing systems are updated (by the end of 2029), to date the interval data for unbundled customers enrolled in their expanded RTP pilots has not been provided for all customers and has been delayed by technical errors that are being sorted. While the verbal commitments made by PG&E are appreciated, the actual implementation of these commitments for all three IOUs needs improvement and direction from the Commission to ensure timely, accurate data sharing. The Commission should keep this proceeding open to address the scoped issue of ensuring unbundled access to dynamic rates by requiring IOUs to provide accurate, hourly, billing-quality interval data.

C. The Commission Should Establish a New Track to Address Standards for Data Sharing, Systems and Process, and Changes Based on Pilot Evaluations

The Commission should establish a separate track or phase of this proceeding to develop standards for these data-sharing processes and additional scoped issues such as systems and processes (and cost recovery for those systems and processes) to enable DF rates. Urgent action is needed to finalize guidance on scoping issues 4, 5, and 6 because the DF rate design guidance the PD orders cannot successfully be implemented without this guidance. Systems and data sharing processes are the technological infrastructure underpinning DF rate availability. Given these issues were clearly in scope and the successful implementation of DF rates depends on them being resolved, the Commission cannot lawfully fail to address them in the instant proceeding.

In addition, by issuing rate design guidance before the mid-term pilot evaluations, the Commission risks ordering rate design guidance that is not effective. The mid-term and final evaluations for the expanded RTP pilots are still outstanding and could provide helpful guidance

[34] D.04-12-046, *Order Resolving Phase 1 Issues on Pricing and Costs Attributable to Community Choice Aggregators and Related Matters*, R.03-10-003 (Dec. 16, 2004), at 51, and 67, COL 30.

informing: (1) changes to the fundamental DF rate structure needed to effectuate the goals of DF; and (2) data access best practices based on the learnings from data sharing during the pilots.

The new track should therefore incorporate the mid-term pilot evaluation results, which are due August 1, 2026, and allow for formal party comment on the evaluation results[35] and also be the venue for addressing all scoped issues (4, 5, and 6) regarding the systems and processes necessary for dynamic pricing and associated cost recovery, unbundled customer access to pricing systems, and enablement of third-party service providers (e.g., automation service providers) to offer support for customers to respond to DF pricing signals. The PD commits to addressing these issues in "one or more new rulemakings," but these rulemakings and their timing have not been defined.

IV. THE PD'S REQUIREMENT THAT THE IOUS REPORT ON THEIR PROCESSES FOR COLLABORATION WITH CCAS ON DF RATE AND PROGRAM FEATURES SHOULD BE ADOPTED AND EXPANDED

CalCCA supports the PD's requirement that IOU DF Rate Proposals incorporate a detailed plan on "how the Large IOUs will collaborate with CCAs on various features of DF rates and DF rate programs…"[36] CalCCA recommends that the PD be modified to also require the IOU DF Rate Proposals to include a description of the specific manner in which CCAs will be able to interact with the IOU systems enabling DF rates (e.g., the price machine).

In addition, the DF Rate Proposals should include a description of the IOUs' ASP oversight responsibilities, including ensuring accurate and accessible outreach content. While the PD covers collaboration on developing generation and distribution components, subscription design, bill protection, ME&O efforts, and conformance with CEC LMS requirements, it does not address sharing information with CCAs or customers around ASPs. ASPs are critical to enabling automated customer responses to DF rates. The IOUs should be required to identify in their DF proposals how bundled and unbundled customers will receive ASP access information, if at all, and coordinate with CCAs on the ME&O plans to enable that access to unbundled customers.

The CCAs look forward to reviewing and commenting on these detailed plans in the proceedings in which they are filed, and to collaborating with the IOUs on DF rates.

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[35] D.24-01-032, Ordering Paragraph 37.

[36] *Id.,* COL 34, at 133.

V. THE COMMISSION SHOULD ADOPT THE PD'S RATE DESIGN GUIDANCE

CalCCA appreciates the PD's guidance on rate design for LSE participation in DF rate programs. The PD finds it reasonable that each LSE has the ability to offer DF rates based on the characteristics of its customer base, develop its own dynamic generation rate, and that bundled and unbundled customers should have a uniform delivery rate component.[37] The findings in the PD should be adopted as they promote consistency and flexibility in incentivizing customers to shift load and equity in accessing load shift benefits through a consistent delivery rate. However, these findings do not address how the unbundled dynamic generation rates will be *implemented*, which must be decided in conjunction with the systems and processes described in scoped item 4.

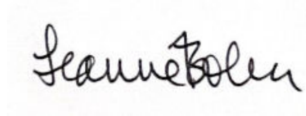
Additionally, the PD's guidance for IOU rate design proposals is appropriate as *interim* guidance but should be revisited once the DF expanded pilot evaluation results are finalized. The PD provides the IOUs with optionality with regard to the recovery of non-marginal costs and customer protections. IOUs are provided the option of using either an Equal Percentage of Marginal Cost scalar or a Revenue Neutral Adder and are given four options for ensuring customer bill protection. This optionality is essential at this early stage of DF rate design development and appropriate because learnings from the piloting of DF rates have not been gathered as the pilots are still ongoing. Additionally, due to the lack of guidance provided in the PD on systems and processes, providing IOUs with flexibility regarding these components in turn provides flexibility to CCAs who may choose to use the IOU DF rate design structure or modify it to support their own DF offerings. The optionality proposed in the PD for recovery of non-marginal costs and ensuring customer protection should therefore be adopted.

VI. CONCLUSION

CalCCA respectfully requests adoption of the recommendations proposed herein. For the foregoing reasons, the PD should be modified as provided in Appendix A, attached hereto.

[37] PD, at 124.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

August 14, 2025

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION

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

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

FINDINGS OF FACT

CONCLUSIONS OF LAW

34. It is reasonable to require the Large IOU's DF Rate Proposals to include a detailed description **<u>of how CCAs will be able to interact with the IOU price machine or other IOU systems enabling DF rates and</u>** regarding how the Large IOUs will collaborate with CCAs on various features of DF rates and DF rate programs, including but not limited to:

a. developing generation and distribution components and customer bill protection and management elements of DF rates, such as subscription design and transactive options;

b. creating and launching LSE DF programs with IOU DF programs, to utilize lessons learned from IOU DF pilots and ME&O efforts and foster customer understanding of **<u>ASP services</u>**, **<u>and</u>** both bundled and unbundled DF rate offerings; and

c. ensuring that LSE DF rates conform with CEC LMS requirements.

ORDERING PARAGRAPHS

8. ~~**Rulemaking 22-07-005 is closed.**~~ **<u>Rulemaking 22-07-005 will remain open to consider unaddressed scoped issues, including the systems and processes necessary for bundled and unbundled customers to have access to dynamic electricity prices and respond to price signals, which includes ensuring community choice aggregators have accurate and consistent customer data to bill and provide access to dynamic rates for their unbundled customers.</u>**

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes.	R.25-06-019

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE ORDER INSTITUTING RULEMAKING

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Lauren Carr,
Senior Manager, Regulatory Affairs & Market Policy
Eric Little,
Director of Market Design

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

August 18, 2025

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SUMMARY OF RECOMMENDATIONS[1]

- Provide LSEs no less than six months after the IRP filing requirements are issued to file individual IRP plans, as unanimously agreed upon by LSE parties;
- Reject ACP-CA and TURN's recommendations for near-term procurement orders because they ignore the numerous constraints influencing ITC and PTC eligibility, are not based upon a demonstrated need, and will raise costs and distort the market;
- Adopt PG&E's recommendation to include load forecasting issues in scope of the proceeding, given the load forecast's increased uncertainty with the emergence of new large loads and the impact it will have on long-term procurement requirements established in RCPPP;
- Compare the costs of resource and transmission alternatives to meet local area needs before adopting party recommendations on local resource procurement to ensure the state pursues the least cost alternative;
- Align RCPPP with the RA and RPS compliance programs, as recommended by AReM;
- Reject party recommendations for LLT resource-specific procurement orders;
- Reject ACP-CA's recommendation for the IOUs to conduct central procurement in coordination with DWR;
- Prioritize affordability when setting the pace of enforceable GHG-emission reduction requirements in RCPPP, as recommended by SDG&E; and
- Adopt PG&E's recommendation for the Commission to continue its support of the TED task force.

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes.	R.25-06-019

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY COMMENTS ON THE ORDER INSTITUTING RULEMAKING

The California Community Choice Association[2] (CalCCA) submits these reply comments pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure[3] on the *Order Instituting Rulemaking*[4] (OIR), issued July 2, 2025, and the directives therein. The OIR will be the new primary venue for the Commission's oversight of the integrated resources planning (IRP) process, which was designed in Rulemaking (R.) 16-02-007, and continued in R.20-05-003.

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

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

4 *Order Instituting Rulemaking,* R.25-06-019 (July 2, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K276/571276511.PDF.

I. INTRODUCTION

Party Opening Comments[5] demonstrate the breadth and importance of this proceeding as it relates to resource planning and procurement to serve the state's reliability and policy objectives. Parties generally align on several key issues. ***First***, parties representing load serving entities (LSE) unanimously agree that given the complex modeling, analysis, and other efforts involved in developing individual LSE IRP plans, the Commission should provide LSEs no less than six months following the issuance of IRP filing requirements to submit their plans. ***Second***, several parties agree that load forecasting issues should be in the scope of the proceeding, given the load forecast's increased importance for long-term procurement and uncertainty with the emergence of new large loads. ***Third***, parties agree that the IRP proceeding must increase its focus on local areas. In addition, CalCCA agrees with parties who recommend the alignment of the Reliable and Clean Power Procurement Program (RCPPP) with existing compliance programs, that affordability must be an express objective of the proceeding, and that the Commission should continue its engagement in the Tracking Energy Development (TED) task force.

However, CalCCA disagrees with some party recommendations, including recommendations for near-term procurement orders without a clear demonstration of need and recommendations for considering long-lead time (LLT) resource-specific procurement orders. These recommendations could raise costs, cause market distortions, and cause misalignment with the current procurement processes and timelines. CalCCA also disagrees with recommendations for additional central procurement, done by the investor-owned utilities (IOU) in coordination with the Department of Water Resources (DWR), as these recommendations would have the IOUs potentially competing with other LSEs who are trying to procure their requirements, even

[5] References to Opening Comments refer to those submitted on or about August 4, 2025, in R.25-06-019.

when the IOUs have not proven to be any more successful at meeting their own mid-term reliability (MTR) procurement needs than other LSEs. For these reasons, CalCCA recommends that the Commission:

- Provide LSEs no less than six months after the IRP filing requirements are issued to file individual IRP plans, as unanimously agreed upon by LSE parties;
- Reject American Clean Power – California (ACP-CA) and The Utility Reform Network's (TURN) recommendations for near-term procurement orders because they ignore the numerous constraints influencing investment tax credit (ITC) and production tax credit (PTC) eligibility, are not based upon a demonstrated need, and will raise costs and distort the market;
- Adopt Pacific Gas & Electric Company's (PG&E) recommendation to include load forecasting issues in scope of the proceeding, given the load forecast's increased uncertainty with the emergence of new large loads and impact it will have on long-term procurement requirements established in the RCPPP;
- Compare the costs of resource and transmission alternatives to meet local area needs before adopting party recommendations on local resource procurement to ensure the state pursues the least cost alternative;
- Align RCPPP with the Resource Adequacy (RA) and Renewables Portfolio Standard (RPS) compliance programs, as recommended by the Alliance for Retail Energy Markets (AReM);
- Reject party recommendations for LLT resource-specific procurement orders;
- Reject ACP-CA's recommendation for the IOUs to conduct central procurement in coordination with DWR;
- Prioritize affordability when setting the pace of enforceable greenhouse-gas (GHG)-emission reduction requirements in RCPPP, as recommended by San Diego Gas & Electric Company (SDG&E); and
- Adopt PG&E's recommendation for the Commission to continue its support of the TED task force.

II. THE COMMISSION SHOULD PROVIDE LSES NO LESS THAN SIX MONTHS AFTER THE IRP FILING REQUIREMENTS ARE ISSUED TO FILE INDIVIDUAL IRP PLANS, AS UNANIMOUSLY AGREED UPON BY LSE PARTIES

LSE parties unanimously agree that the Commission should provide LSEs no less than six months after the final IRP filing requirements are issued to file their individual IRP plans.[6] As SDG&E states, the OIR's proposed schedule "provides LSEs with four months or less to conduct the extensive modeling, analysis, and other work that is necessary to produce a robust and compliant [individual IRP] filing. The OIR's proposed schedule is a significant – and problematic – reduction in preparation time as compared with previous IRP cycles."[7]

The Commission should therefore modify the deadline for LSEs to file their next individual IRPs to be six months after the Commission issues all filing requirements, including modeling inputs and assumptions, and templates. The Commission should also adopt PG&E's recommendation that it "use the updated procurement plans from LSEs' resource data template submissions rather than the IRP plans that LSEs filed in November 2022" when developing Preferred System Plan (PSP) and Transmission Planning Process (TPP) portfolios, given the 2022 IRP filings are "already stale, and with the 2024 IRP filings delayed into 2026, the data will only become staler."[8]

III. ACP-CA AND TURN'S RECOMMENDATIONS FOR NEAR-TERM PROCUREMENT ORDERS SHOULD BE REJECTED

The Commission should reject recommendations by TURN and ACP-CA for near-term procurement orders. These parties: (1) do not base their recommendations on a demonstrated

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6 *See* AReM Opening Comments, at 3; Ava Community Energy (Ava) Opening Comments, at 3; CalCCA Opening Comments, at 20; PG&E Opening Comments, at 13; Southern California Edison Company (SCE) Opening Comments, at 2; and SDG&E Opening Comments, at 4.

7 SDG&E Opening Comments, at 4.

8 PG&E Opening Comments, at 11.

need; (2) advance proposals that will raise costs and distort the market, and (3) ignore the numerous constraints influencing ITC and PTC eligibility.

TURN recommends that the Commission "issue an immediate interim procurement order directing all [LSEs] to contract for wind and solar generation expected to be eligible for the relevant federal tax credits due to their ability to commence (or complete) construction by the relevant deadlines in OBBB."[9] ACP-CA recommends the Commission "move to implement the proposed immediate procurement track included in ACP-California's recent motion in R.20-05-003 (*i.e.*, directing an unbounded procurement order to capture fleeting tax credits)."[10] ACP-CA's motion requests the Commission order the IOUs to conduct procurement on behalf of all LSEs. ACP-CA also recommends an additional near-term procurement order, which would "not be designed to maximize tax credits, but rather shore up reliability and clean energy needs in the 2028-2032 timeframe," while staging the development and implementation of RCPPP, as proposed in its July 15, 2025, joint proposal on RCPPP.[11]

The Commission should reject these recommendations for several reasons, expressed in CalCCA's August 5, 2025, Reply Comments on RCPPP[12] and Response to the ACP-CA motion in R.20-05-003.[13] ***First***, there are numerous other constraints that may make projects ineligible for ITC and PTC, even if the Commission orders immediate procurement, in addition to the

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9 TURN Opening Comments, at 2.

10 ACP-CA Opening Comments, at 2.

11 *Id.*, at 3.

12 *See California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (Aug. 5, 2025), at 5-11: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M575/K458/575458274.PDF.

13 *See California Community Choice Association's Response to American Clean Power – California Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*, R.20-05-003 (Aug. 5, 2025): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M575/K544/575544426.PDF.

expiration of those credits. Other Federal guidance impacting the ability to meet the OBBBA[14] deadlines requires:

> [A]ll decisions, actions, consultations, and other undertakings—including but not limited to the following—related to wind and solar energy facilities shall require submission to the Office of the Executive secretariat and Regulatory Affairs, subsequent review by the Office of the Deputy Secretary, and final review by the Office of the Secretary."[15]

This is followed by a list of 69 items that must be reviewed. This process will likely introduce additional delays to bring eligible resources to commercial operation date (COD). Federal guidance continues to evolve, making the availability of ITC and PTC more uncertain and challenging to obtain.[16]

Issues of supply chain, interconnection (primarily related to equipment availability), and permitting also affect the ability of LSEs to bring these resources to COD. None of these problems are solved by pushing even more demand into an already constrained market. Doing so will not make the components more available, the interconnection completed more timely, or speed up the permitting process. Rather than putting even more pressure on the resource development process, the Commission should seek to reduce barriers preventing in-development resources from reaching COD in a timely manner.

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14 H.R.1 - 119th Congress (2025-2026): One Big Beautiful Bill Act, H.R.1, 119th Cong. (2025), https://www.congress.gov/bill/119th-congress/house-bill/1.

15 *Departmental Review Procedures for Decisions, Actions, Consultations, and Other Undertakings Related to Wind and Solar Energy Facilities Department of the Interior* (July 15, 2025): https://www.doi.gov/media/document/departmental-review-procedures-decisions-actions-consultations-and-other.

16 On August 1, 2025, the Secretary of the Interior issued Order No. 3439, directing the U.S. Department of the Interior to consider land use density when evaluating wind and solar project applications — effectively discouraging "low-density" renewable energy uses. *See Order 3438 Managing Federal Energy Resources and Protecting the Environment* (Aug. 1, 2025): https://www.doi.gov/document-library/secretary-order/so-3438-managing-federal-energy-resources-and-protecting.

Second, neither TURN nor ACP-CA sufficiently demonstrate a need for immediate procurement orders. TURN cites to the wind and solar amounts in the TPP portfolios, and recommends the Commission assign uncontracted portions of these amounts to LSEs in an interim procurement order.[17] ACP-CA states "a full analysis conducted by Energy Division and its consultants *will likely* unearth substantial clean energy and reliability needs in the 2028-2032 timeframe,"[18] but such analysis has not yet been completed. Neither TURN nor ACP-CA recommend a process in advance of issuing an immediate procurement order for the Commission to conduct "probabilistic reliability modeling" to ensure sufficient capacity for short and midterm reliability needs, and to review the results of that modeling in a public proceeding, as required by Public Utilities Code section 454.52.[19][20]

Third, immediate procurement orders will raise costs and distort the market in which LSEs are already procuring to meet their own needs, including meeting MTR, RPS, and internal goals. While ACP-CA claims there is a "newly heightened urgency for clean resource procurement based on the passage of [the OBBBA],"[21] there are no guarantees that the prices developers will actually offer for these projects will be cost-effective. If the developers were unable to sell their projects to LSEs *before* the OBBBA, possibly because of the prices they sought, will a procurement order improve the situation? Further, adoption of ACP-CA's motion would result in the IOUs attempting to procure all wind and solar resources in the CAISO's

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17 *See* TURN Opening Comments, at 2.

18 ACP-CA Opening Comments, at 3 (emphasis added) (footnote omitted).

19 Section 454.52 describes the IRP process and requiring the Commission to "aggregate reported short-term and midterm resource procurement from all [LSEs]" under the RA and IRP statutes "in furtherance of avoiding unplanned energy supply shortfalls or expensive emergency procurement and ensuring a more accurate understanding of electrical grid operational needs."

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

21 ACP-CA Opening Comments, at 2.

interconnection queue cluster 14 through central procurement ***at the same time*** all LSEs are attempting to procure to meet their own needs. In addition, all LSEs are acutely aware of the deadlines to qualify for ITC and PTC. It is reasonable to expect that those LSEs are also likely ramping up their procurement to obtain resources that may be lower cost than resources that are unable to obtain ITC or PTC. This is already increasing demand placing upward pressure on prices. Further demand exerting more force on prices and taking away from the procurement autonomy of the LSEs is not warranted.

IV. ADOPT PG&E'S RECOMMENDATION TO INCLUDE LOAD FORECASTING ISSUES IN SCOPE

CalCCA agrees with PG&E, which states:

> Given the scale of this potential load [from data centers and advanced manufacturing] and the impact it will have on both planning models and procurement processes, it is imperative that the Commission consider a range of possible outcomes so California does not overbuild and create stranded assets that have negative implications for long-term customer affordability, while at the same time ensuring the grid is reliable and not a constraint on economic growth in California.[22]

Current market and policy conditions have increased load forecasting uncertainty. These include significant shifts in federal policies [23] and the emergence of large loads including data centers. Utilizing load forecasts to determine procurement requirements is like riding a bicycle on a ridgeline, turning too far in either direction can have significant consequences. Greater uncertainty in the forecast increases these consequences. Under-forecasting can lead to insufficient resources to meet actual energy needs with reliability and/or clean energy risks,

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22 PG&E Opening Comments, at 4 (footnote omitted).

23 Presentations by the Participating Transmission Owners at the CAISO's July 30, 2025, Transmission Development Forum revealed that 52 of the 86 projects reported are experiencing a delay in reaching commercial operation: https://www.caiso.com/meetings-events/topics/transmission-development-forum.

while over-forecasting can result in an overbuild with costs that are not absorbed by additional load putting affordability in peril.

To address load forecasting uncertainty, the California Energy Commission (CEC) has proposed to create multiple scenarios to evaluate forecasts. While this is a positive step, ultimately a specific scenario must be chosen to serve as the basis for procurement obligations like RA and RCPPP. During the August 6, 2025, Load Forecast Inputs and Assumptions Commissioner Workshop at the CEC, it was stated that the elements historically influencing load (demographics and economics), are overshadowed by changes in the load forecast due to other elements, the most notable of which is the energization of large loads like data centers. However, the influence of large loads is not completely understood at this time and contains significant uncertainty regarding its realization. In a July 16, 2025, CEC Demand Analysis Working Group (DAWG) meeting, PG&E and SCE presented material indicating that data center load growth is highly uncertain.[24]

Due to this uncertainty and the significant consequences of incorrect forecasting, CalCCA recommends that the Commission and LSEs work closely together in a separate track to ensure the most accurate forecast, as well as to ensure that all parties have sufficient access to the data to use in evaluating their own needs like procurement. This should occur in conjunction with the CEC's and stakeholder's load forecasting efforts related to data centers. This separate track should also include more transparency around the confidence that a load will come to fruition. This should include a standardized milestone evaluation of large loads including data

[24] During the DAWG meeting, PG&E presented that, "For multiple forecast cycles, forecasts will likely be highly uncertain due to the nascency of the data center technology & markets and due to the complexity of data center projects." and SCE indicated that they had increased the likelihood of eight projects, decreased the likelihood of 19 projects and retained the likelihood of 16 projects. https://www.energy.ca.gov/event/meeting/2025-07/ca-energy-demand-forecast-economic-demographic-inputs-and-data-center.

centers to help inform the confidence of the forecast values as well as determining the forecast value itself.

V. THE COMMISSION SHOULD COMPARE THE COSTS OF RESOURCE AND TRANSMISSION ALTERNATIVES TO MEET LOCAL AREA NEEDS BEFORE ADOPTING PARTY RECOMMENDATIONS ON LOCAL RESOURCE PROCUREMENT TO ENSURE THE STATE PURSUES THE LEAST COST ALTERNATIVE

California Environmental Justice Alliance (CEJA) recommends this proceeding include the "[d]evelopment of a staff proposal on how to incentivize local procurement, to the extent not already addressed in the RCPPP" and that the proceeding include the "[d]evelopment of a requirement to include local procurement targets in IRP [LSE] plans, and eventually into procurement."[25] CalCCA agrees with CEJA that decarbonization of the State's electricity market needs to examine local areas, which contain a significant amount of emitting resources. However, CEJA's recommendation should be amended to include additional steps to gather information needed to make a least-cos t determination since the market lacks visibility into the alternatives.

Local area constraints can be addressed by local generation, transmission investments that relieve the constraint allowing competing system resources to supply the local energy needs, or some combination of both. This is not a simple task. To determine the optimal local resource build, it is necessary to understand the locational effectiveness of the resource (including the effectiveness of distributed energy resources), the suitability of the land, the availability of the land, and the cost of the land. Each of these will have a significant impact on the cost of building a non-emitting resource in the local area that is not correctly reflected in more generic Net Cost of New Entry (CONE) values. In addition, the evaluation would need to include whether there is

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[25] CEJA Opening Comments, at 3.

a sufficient amount of land in locations that would develop competition among developers to avoid market power. Currently, the local RA program contains a waiver process and a reliability must-run backstop contract, both of which can be used to counteract the potential for market power in the constrained local areas. Without assurances that a market for the development of non-emitting resources in locally constrained areas will produce competitive outcomes, the cost of such procurement must be included in comparison with the alternative. In addition, to the extent that these resources require network upgrades to be fully deliverable and not just meet the local area need, the costs of those upgrades would need to be evaluated in the analysis to compare to the deliverability costs of resources outside of the local area thus comparing the total cost of each resource to meet reliability needs of the grid.

That alternative is the upgrading (including new build) of transmission. Such a process will necessarily involve the CAISO to evaluate what transmission changes are necessary to alleviate the constraints prohibiting system non-emitting resources from serving the local area load. This would then inform the TPP of the need for investment. With this information, estimates of the cost of transmission upgrades can be developed and compared to the cost of new non-emitting resource build in the local area. Only when these cost estimations are known can the State make a least cost decision knowing the risks and benefits of each methodology. In addition, it can evaluate solutions that require some of each alternative (*i.e.*, some transmission infrastructure development with some new non-emitting generation in the local area). Once that evaluation is complete, then the State can move forward with CAISO transmission development and/or LSE investment in new local non-emitting generation. In addition, to the extent the solution is distributed energy resources, the Commission can work with the IOUs and the CAISO to ensure the Wholesale Distribution Access Tariff process is effective at interconnecting such resources to meet reliability needs.

VI. RCPPP SHOULD BE ALIGNED WITH THE RA AND RPS COMPLIANCE PROGRAMS, AS RECOMMENDED BY AREM

CalCCA agrees with AReM that the implementation of RCPPP should be closely coordinated with the RA and RPS proceedings.[26] Both AReM and CalCCA support RCPPP frameworks that align closely with the RA and RPS programs through multi-year forward reliability requirements using the slice-of-day (SOD) methodology and a clean energy standard built upon the RPS framework.[27] Aligning RCPPP with these existing programs will ensure long-term and near-term planning and procurement efforts work together to achieve reliability and emissions reduction in a cost-effective manner. The Commission should therefore adopt AReM's recommendation, "[t]o ensure clarity and effective coordination, the Commission should clearly designate how the three relevant proceedings will align, so that parties understand where to address any remaining issues following the initial RCPPP framework decision."[28]

VII. THE COMMISSION SHOULD REJECT PARTY RECOMMENDATIONS FOR LLT RESOURCE-SPECIFIC PROCUREMENT ORDERS

The Commission should reject party recommendations for technology-specific procurement requirements.[29] Allowing LSEs to make their own procurement decisions, as opposed to prescribing procurement of specific technology types, will allow the market to decide

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26 *See* AReM Opening Comments, at 2.

27 *See Comments of the Alliance For Retail Energy Markets on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal,* R.20-05-003 (July 15, 2025), at 3-7: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M573/K391/573391830.PDF; and *California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (Aug. 5, 2025), at 12-14: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M575/K458/575458274.PDF.

28 AReM Opening Comments, at 2.

29 *See* Bioenergy Association of California Opening Comments, at 5-6, The Environmental Defense Fund (EDF) Opening Comments, at 1-2; Mainspring Energy, Inc. (Mainspring) Opening Comments, at 5; Southern California Gas Company Opening Comments, at 1-4.

the most cost-effective projects to pursue that possess the right attributes to meet reliability and GHG-reduction targets.

EDF recommends the Commission issue procurement orders "specifically aimed" at procuring LLT resources not procured by CDWR.[30] If DWR or LSEs forego the procurement of LLT resources, one possible reason could be because the resources are not cost-effective. The Commission should not force LSEs to procure resources that are not cost-effective if an alternative portfolio of resources that is more cost-effective can meet the same reliability need and GHG reduction targets. If LLT resources are the most cost-effective way to obtain all the attributes necessary to meet reliability needs, then LSEs will procure them to meet their compliance obligations. The IRP program does not need an LLT-specific requirement for needs to be met.

CalCCA surveyed its members, receiving responses from 12 members representing over five million customers and 205 terawatt hours of energy sales annually. When asked if the CCA had selected any non-solar and non-storage resources in recent (*i.e.*, in the last five years) request for offers (RFO), a very small fraction said that they had done so because the resource was priced at or below net CONE. Instead, most were procured at costs above net CONE and most of those were the result of meeting MTR requirements for LLT resources or base load non-emitting resources. In addition, CalCCA asked if the CCAs had declined offers from non-solar/non-storage resources over that same time frame. Most entities indicated that there were no or very few offers that they declined. In addition to those CCAs, one indicated that it received a reasonable number of offers but like other CCAs, they declined the offers as they were above the net CONE value and not economic compared to other alternatives to fill their portfolio needs.

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[30] *See* EDF Opening Comments, at 1-2.

Technology specific procurement requirements for technologies that are unavailable at a reasonable price will simply increase costs and challenge compliance.

Mainspring recommends minimum procurement thresholds for "high [Effective Load Carrying Capability] resources that are also RPS-eligible."[31] Opening Comments filed on July 15, 2025, in response to the RCPPP Staff Proposal demonstrate many parties support a shift away from ELCC towards SOD,[32] so it is premature to consider procurement requirements based upon ELCC as Mainspring suggests.

VIII. ACP-CA'S RECOMMENDATION FOR THE IOUS TO CONDUCT CENTRAL PROCUREMENT IN COORDINATION WITH DWR SHOULD BE REJECTED

The Commission should reject ACP-CA's recommendation to authorize the IOUs to collaborate with DWR on central procurement. ACP-CA recommends that the Commission should "proactively evaluate the ability of another entity to conduct [central] procurement in close coordination with DWR and within the timeframes contemplated in D.24-08-064" and specifically recommends the IOUs for this role.[33] The Commission should reject this recommendation for several reasons.

First, the Commission should not rely on the IOUs as a central procurement entity as statute recognizes that "CCAs shall be solely responsible for all generation procurement activities on behalf of the [CCA's] customers."[34] Section 366.2 also states that the Commission

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31 Mainspring Opening Comments, at 5.

32 *See* ACP-CA Opening Comments, at 4-5; Advanced Energy United Opening Comments, at 3; AReM Opening Comments, at 3-11; Ava Opening Comments, Attachment A, at 2; CEJA, Sierra Club, and Center for Energy Efficiency and Renewable Technologies Opening Comments, at 19-22; the California Large Energy Consumers Association Opening Comments, at 4; GPI Opening Comments, at 3; PG&E Opening Comments, at 10; SDG&E Opening Comments, at 17; Silicon Valley Clean Energy Opening Comments, at 6-7; and CalCCA Opening Comments, at 12-1, (filed on or about July 15, 2025, in R.20-05-003.

33 ACP-CA Opening Comments, at 5.

34 Public Utilities Code § 366.2(a)(5).

can require "other generation procurement arrangements expressly authorized by statute," and the Commission has already authorized DWR, and not the IOUs, to serve this role. ***Second***, as explained by SCE in its July 15, 2025, Opening Comments on the RCPPP Staff Proposal, the IOUs would not be able to procure while adhering to their competitive neutrality rules since the IOU would be procuring the same product at the same time that all LSEs are procuring to meet reliability needs and procurement obligations.[35] Having an IOU compete with other LSEs who are trying to procure their requirements could result in an LSE not meeting its requirements due to the competition by the IOU at the same time. ***Third***, the IOUs have not proven to be any more successful at meeting their own procurement needs than other LSEs,[36] so it is not likely that the IOUs are best suited to serve the function ACP-CA describes.

IX. RCPPP SHOULD SET THE PACE OF ENFORCEABLE GHG EMISSION REDUCTION REQUIREMENTS IN AN AFFORDABLE MANNER

CalCCA agrees with SDG&E that the Commission should prioritize affordability when considering IRP analyses to set mandatory procurement obligations within RCPPP. SDG&E recommends that, "in this and future IRP cycles, the Commission should conduct and evaluate a cost comparison between achieving any proposed IRP GHG-reduction target and that of achieving statutory minimums."[37] CalCCA agrees with the Green Power Institute (GPI) that intermediate RPS targets are predicated on meeting ultimate goals "on a smooth trajectory,"[38]

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35 *Southern California Edison Company's (U 338-E) Comments on Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (July 15, 2025), at 43: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M573/K513/573513397.PDF.

36 *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (July 15, 2025), at 18-20: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M573/K513/573513376.PDF.

37 *Id.*, at 3.

38 GPI Opening Comments, at 2.

and recommends that the Commission consider affordability in RCPPP when setting the pace of enforceable GHG reduction requirements to achieve ultimate statutory goals.

X. THE COMMISSION SHOULD ADOPT PG&E'S RECOMMENDATION FOR THE COMMISSION TO CONTINUE ITS SUPPORT OF THE TED TASK FORCE

CalCCA supports PG&E's recommendation for the Commission to continue supporting the TED task force and consider expanding the publication of information in its Resource Tracking Data Report.[39] The TED task force has been successful in coordinating with LSEs and developers to overcome barriers to advancing projects through the development process. As described above, barriers to resource development continue to challenge the ability to get resources online in a timely and cost-effective manner. The Commission should therefore continue its efforts to support the TED task force.

XI. CONCLUSION

CalCCA appreciates the opportunity to submit these comments and respectfully requests adoption of the recommendations proposed herein.

Respectfully submitted,

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

August 18, 2025

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39 *See* PG&E Opening Comments, at 12.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

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

Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
Eric Little,
Director of Market Design
Willie Calvin,
Regulatory Case Manager

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

August 19, 2025

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SUMMARY OF RECOMMENDATIONS[1]

- The Commission should keep the proceeding open, as recommended in CalCCA Opening Comments, as PG&E and SCE Opening Comments highlight the need to establish systems and processes to enable CCAs to offer DF rates to unbundled customers;
- PG&E's recommendation for more time for IOUs to develop DF Rate Proposals should be adopted to allow for meaningful collaboration with CCAs; and
- Cal Advocates' comments on cost-shift risks between IOUs and CCAs ignore the two-way nature of cost shifting and should not be used to prevent IOU and CCA collaboration.

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

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

The California Community Choice Association (CalCCA) submits these reply comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure on the proposed *Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals*[2] (Proposed Decision), dated July 25, 2025.

I. INTRODUCTION

These Reply Comments focus on the Opening Comments of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), and The Public Advocates Office at the California Public Utilities Commission (Cal Advocates).[3]

First, PG&E and SCE's opposition to Conclusion of Law (COL) 34, which puts the responsibility of ensuring CCAs can comply with California Energy Commission Load Management Standards (LMS) on the investor-owned utilities (IOU), highlights the need to keep the proceeding open. PG&E points out correctly that CCA rates are approved by their CCA boards, not by the Commission. The guidance from the Commission in COL 34 oversteps both on IOUs and CCAs and ignores the simpler solution of keeping the proceeding open to continue addressing scoped items. While IOU and CCA collaboration is critical to the success of demand flexibility (DF) rates, the Proposed Decision avoids the Commission's responsibility to follow through on addressing the goals of the proceeding by attempting to force the IOUs and CCAs to collaborate in silos, an inefficient and ineffective strategy.

Second, the Commission should adopt PG&E's proposal to extend the timeframe to allow for IOU and CCA collaboration for DF Rate Proposals and allow a follow-up advice letter to incorporate real-time pricing (RTP) pilot evaluation learnings. PG&E states that a 45-day timeline is insufficient to perform the analyses and collaborate with CCAs, as the Proposed Decision directs for IOU DF Rate Proposals. SDG&E makes similar recommendations to allow for more time for SDG&E to incorporate results from RTP pilot evaluations. RTP pilots are still ongoing, and stakeholders have yet to see the results of either the mid-term or final evaluations for those pilots. Providing more time for meaningful

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2 [Proposed] *Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals*, Rulemaking (R.) 22-07-005 (July 25, 2025).

3 All references herein to party Opening Comments are to the Opening Comments filed in this Rulemaking, R.22-07-005, on or about August 14, 2025.

CCA collaboration with the IOUs for IOU DF rate proposals is reasonable, as is creating a process to incorporate results from the RTP pilot evaluations.

Third, the Commission should reject Cal Advocates' calls for a rejection of the Proposed Decision, in part, because it does not address potential cost-shifting risks that bundled customers would bear because it simplifies issues at play for DF rate development and implementation. While CalCCA agrees that the Proposed Decision does not address Scoping Issues 4 and 5, the cost-shifting risks at play are a two-way street. Unbundled customers are also at risk of subsidizing bundled customers if systems are designed so that they must pay twice for DF-enabled systems and processes; once for bundled customers and a second time for any CCA-specific differences. This is precisely why keeping the proceeding open is crucial in these early stages of DF rate development. Additionally, Cal Advocates Opening Comments point to specific revisions to COL 34 in the Proposed Decision in Appendix A; however, no such revisions appear in Appendix A. Without these revisions, other parties cannot know whether Cal Advocates' specific recommendations are reasonable.

For these reasons, CalCCA respectfully recommends:

- The Commission should keep the proceeding open, as recommended in CalCCA Opening Comments, as PG&E and SCE Opening Comments highlight the need to establish systems and processes to enable CCAs to offer DF rates to unbundled customers;

- PG&E's recommendation for more time for IOUs to develop DF Rate Proposals should be adopted to allow for meaningful collaboration with CCAs; and

- Cal Advocates' comments on cost-shift risks between IOUs and CCAs ignore the two-way nature of cost shifting and should not be used to prevent IOU and CCA collaboration.

II. PG&E AND SCE OPENING COMMENTS HIGHLIGHT THE NEED TO KEEP THE PROCEEDING OPEN TO ESTABLISH SYSTEMS AND PROCESSES TO ENABLE CCAS TO OFFER DF RATES TO UNBUNDLED CUSTOMERS

Comments by PG&E and SCE reflect the need to keep the proceeding open to establish systems and processes to enable CCAs to offer DF rates to unbundled customers. Both IOUs state that they should not be responsible for CCA compliance with CEC LMS,[4] and PG&E goes further to clarify that the Commission does not have jurisdiction over CCAs developing and adopting their own rates.[5] Indeed,

[4] *See* PG&E Opening Comments, at 13-14; *See also* SCE Opening Comments, at 14.

[5] PG&E Opening Comments, at 14 (Clarifying that CCA Boards are responsible for developing and adopting new rates, not the Commission) ("As a matter of law, neither the [Commission] itself, nor any IOU it regulates have any oversight role, or power to 'ensure' CCA rate proposals are LMS-compliant.").

the Commission does not have jurisdiction over CCA rates and the Proposed Decision's guidance to the IOUs highlights a significant piece missing from the Proposed Decision; guidance on Scoping Issue 4 on systems and processes for enabling DF rates.[6]

Addressing Scoping Issue 4 in another track would also address SCE's concern in Opening Comments. SCE states, "[i]f the Commission feels strongly that IOUs perform additional work to design and calculate the DF rates, design programs, or ensure regulatory compliance for the CCAs, then the CCAs should be required to pay their appropriate share of the cost to implement, integrate and maintain their DF rates in the IOU's respective billing system(s)."[7] SCE's statement oversimplifies the mechanics needed to integrate bundled and unbundled DF rates, but its reaction to COL 34[8] highlights the challenges posed by the Proposed Decision's attempt to make IOUs and CCAs answer the questions included in Scoping Issue 4 of the proceeding in an expedited and siloed way.

Instead, as CalCCA recommended in its Opening Comments, the Proposed Decision should be revised to keep the proceeding open, in part, to address Scoping Issue 4.[9] As PG&E and SCE point out, the IOUs should not be responsible for ensuring the CCAs comply with LMS, though SCE attempts to avoid its billing duties required by section 366.2(c)(9).[10] Without establishing systems and processes to enable CCAs to offer DF rates, the Commission prejudices CCAs, and the IOUs will move forward to develop systems on their own, which will not satisfy the goal of enabling participation in DF by bundled and unbundled customers.[11] Failing to keep the proceeding open to address scoped items forces IOUs and CCAs to fill in gaps in silos rather than with all stakeholders. This is both inefficient and ineffective. The Commission should keep the proceeding open and initiate a new track to address all scoped issues established in the Scoping Memo as described in CalCCA's Opening Comments.

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6 *Assigned Commissioner's Phase 1 Scoping Memo and Ruling*, R.22-07-005 (Nov. 2, 2022) (Scoping Memo), at 5.

7 SCE Opening Comments, at 14.

8 *See* Proposed Decision, COL 34, (Directing the IOUs to collaborate with LSEs and describe how IOUs will help create and launch LSE DF programs and ensure LSE DF rates conform with CEC LMS requirements).

9 CalCCA Opening Comments, at 10 (Establishing that the Commission failed to address scoped issues).

10 SCE Opening Comments, at 14 (Stating that CCAs must perform their own billing).

11 *Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates*, R.22-07-005 (July 22, 2022) (DF OIR), at 1 (the sixth goal described in the opening paragraph of the DF OIR).

III. PG&E AND SDG&E'S RECOMMENDATION FOR MORE TIME FOR IOUS TO DEVELOP DF RATE PROPOSALS SHOULD BE ADOPTED

The Commission should adopt PG&E's recommendation for more time for the IOUs to develop DF rate proposals.[12] PG&E highlights the need for more than the Proposed Decision's prescribed 45 days to perform RTP-related rate analyses, prepare supplemental testimony to accommodate CCA collaboration, and incorporate conclusions from mid-term RTP pilot evaluations.[13] Indeed, 45 days is not sufficient time for the CCA collaboration directed in the Proposed Decision. IOU and CCA collaboration is important to ensure bundled and unbundled customer equity for DF rates, especially given that IOUs act as CCA billing agents. Forty-five days is not sufficient time to have meaningful and complex conversations about the needs of the CCAs and the abilities of the IOUs to accommodate the complexity of DF rates. Additionally, PG&E and SDG&E both cite the importance of including learnings from actual customer experiences from the RTP pilots, which will have mid-term and final evaluations.[14] As CalCCA argued in Opening Comments, incorporating results from RTP pilot evaluations is a key reason why the Commission should keep the proceeding open and establish a new track to address the remaining scoped items.[15] PG&E recommends submitting supplemental testimony for DF Rate Proposals in November 2026 and for a Tier 1 Advice Letter within 90 days after final RTP pilot evaluations in 2028 that include any additional learnings.[16] SDG&E recommends it be provided 120 days from the completion of mid-term evaluation reports for PG&E's and SCE's expanded pilots to file its DF Rate Proposal Application.[17] The Commission should adopt these recommendations because they allow for meaningful CCA coordination and would allow IOUs to incorporate outcomes from a new track of the proceeding that addresses the remaining scoped items.

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[12] PG&E Opening Comments, at 3-4 (Describing why 45 days is insufficient to perform actions ordered in the Proposed Decision).

[13] *Ibid.*

[14] *Id.*, at 4 (Describing the importance of incorporating mid-term and final pilot evaluation learnings); SDG&E Opening Comments, at 12 (Requesting additional time to allow SDG&E to leverage the results of PG&E and SCE RTP pilot evaluations).

[15] CalCCA Opening Comments, at 13-14 (Describing the scoped issues the Commission should address).

[16] PG&E Opening Comments*,* at 4 (Supporting an Advice Letter process for incorporating final evaluation results); and 7 (Recommending Supplemental Testimony be submitted in November 2026 instead of 45 days after the issuance of the Decision).

[17] *See* SDG&E Opening Comments, at 12.

IV. CAL ADVOCATES' COMMENTS ON COST-SHIFT RISKS BETWEEN IOUS AND CCAS IGNORE THE TWO-WAY NATURE OF COST SHIFTING AND SHOULD NOT BE USED TO PREVENT IOU AND CCA COLLABORATION

The Commission should not use Cal Advocates' comments to prevent IOU and CCA collaboration. Cal Advocates expresses concern with potential cost shifts resulting from the implementation of DF rates, but only cost shifts from bundled to unbundled customers, particularly in the ongoing RTP pilots. In Opening Comments, Cal Advocates states that there is a risk that bundled customers could potentially subsidize DF rates for unbundled customers,[18] but Cal Advocates' statement ignores the two-way nature of cost shifting. Indeed, the Commission should be careful to prevent cost shifts *in both directions* and consider the cost recovery of implementing DF rates, which requires complex information technology integration between IOUs and CCAs. There are risks for unbundled customers to subsidize bundled customer DF rates as well, and there is much unknown about how DF rates will develop, a primary reason why this proceeding should remain open.

Additionally, Cal Advocates calls for the Commission to reject the Proposed Decision due to legal errors associated with the reasonableness of the DF rates proposed, or in the alternative, calls for the Commission to revise COL 34,[19] but amendments to COL 34 are not included in the Cal Advocates comments.[20] While CalCCA does not generally dispute the existence of cost-shifting risks in developing and implementing DF rates, as they are, Cal Advocates' comments provide an incomplete depiction of those risks. If the Commission's goal is a successful roll-out of DF rates to bundled and unbundled customers, then IOU and CCA collaboration is necessary. Cal Advocates' incomplete, one-way concern over cost shifting risks should not be used as a motivation to make any determinations that IOUs should not collaborate with CCAs on DF rate proposals.

V. CONCLUSION

CalCCA appreciates the opportunity to submit these reply comments and requests adoption of the recommendations proposed herein.

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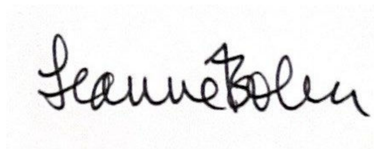
[18] Cal Advocates Opening Comments, at 14.

[19] *Id.*, at 15.

[20] *Id.,* at A-1 to A-4. Cal Advocates' Appendix A contains proposed revisions to the COL, however, stops at recommending changes to COL 29 in the Proposed Decision. Appendix A does not contain revisions to COL 34.

Respectfully submitted,



Leanne Bober,
Director of Regulatory Affairs and Deputy General Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

August 19, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S MOTION FOR LEAVE TO REPLY TO AMERICAN CLEAN POWER-CALIFORNIA REPLY TO RESPONSES TO MOTION TO AMEND THE AMENDED SCOPING MEMO TO INCLUDE AN ADDITIONAL TRACK FOR EXPEDITED PROCUREMENT

Evelyn Kahl,
General Counsel and Chief Policy Officer
Lauren Carr,
Senior Manager, Regulatory Affairs and Market Policy
Eric Little,
Director of Market Design

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

August 22, 2025

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

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S MOTION FOR LEAVE TO REPLY TO AMERICAN CLEAN POWER-CALIFORNIA REPLY TO RESPONSES TO MOTION TO AMEND THE AMENDED SCOPING MEMO TO INCLUDE AN ADDITIONAL TRACK FOR EXPEDITED PROCUREMENT

Pursuant to Rule 11.1(f) of the California Public Utilities Commission's[1] (Commission) Rules of Practice and Procedure, the California Community Choice Association[2] (CalCCA) respectfully files this *Motion for Leave to Reply to American Clean Power-California Reply to Responses to Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement* (CalCCA Motion).

On July 21, 2025, American Clean Power-California (ACP-CA) filed its *American Clean Power-California Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*,[3] which seeks to amend the most recent scoping memo in this proceeding to include a new emergency procurement track separate from procurement proposed

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

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

3 *American Clean Power-California Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*, R.20-05-003 (July 21, 2025).

under the pending Reliable and Clean Power Procurement Program (RCPPP). On August 5, 2025, CalCCA filed a response,[4] recommending the Commission reject the motion.

ACP-CA filed its *Reply to Responses to Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*[5] (ACP-CA Reply), on August 15, 2025. The ACP-CA Reply: (1) mischaracterizes community choice aggregator (CCA) procurement activity; (2) mischaracterizes CalCCA's July 15, 2025, opening comments[6] and August 5, 2025, reply comments[7] to the RCPPP Ruling;[8] and (3) commits legal error in stating "a fully substantiated needs assessment is not necessary to grant the motion."[9]

CalCCA therefore requests permission to file a reply to ACP-CA's Reply to address misleading statements and legal errors to ensure a complete and correct record. CalCCA's proposed reply is attached to this motion as Attachment A for reference and will be filed should the ALJ grant the CalCCA Motion.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl,
General Counsel and Chief Policy Officer
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

August 22, 2025

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[4] *California Community Choice Association's Response to American Clean Power-California Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*, R.20-05-003 (Aug. 5, 2025).

[5] *American Clean Power-California Reply to Responses to Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*, Rulemaking (R.) 20-05-003 (Aug. 15, 2025).

[6] *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (July 15, 2025).

[7] *California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (Aug. 5, 2025).

[8] *Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (Apr. 29, 2025).

[9] ACP-CA Reply, at 3.

ATTACHMENT
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S MOTION FOR LEAVE TO REPLY TO AMERICAN CLEAN POWER-CALIFORNIA REPLY TO RESPONSES TO MOTION TO AMEND THE AMENDED SCOPING MEMO TO INCLUDE AN ADDITIONAL TRACK FOR EXPEDITED PROCUREMENT

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY TO AMERICAN CLEAN POWER-CALIFORNIA REPLY TO RESPONSES TO MOTION TO AMEND THE AMENDED SCOPING MEMO TO INCLUDE AN ADDITIONAL TRACK FOR EXPEDITED PROCUREMENT

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Evelyn Kahl,
General Counsel and Chief Policy Officer
Lauren Carr,
Senior Manager, Regulatory Affairs and Market Policy
Eric Little,
Director of Market Design

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
1121 L Street, Suite 400
Sacramento, CA 95814
Telephone: (510) 980-9459
E-mail: regulatory@cal-cca.org

August 22, 2025

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SUMMARY OF RECOMMENDATIONS[1]

The Commission should dismiss the ACP-CA Reply, because it:

- Mischaracterizes CCA procurement activity;
- Mischaracterizes CalCCA's July 15, 2025, opening comments and August 5, 2025, reply comments to the RCPPP ruling; and
- Commits legal error in stating "a fully substantiated needs assessment is not necessary to grant the motion."

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S REPLY TO AMERICAN CLEAN POWER-CALIFORNIA REPLY TO RESPONSES TO MOTION TO AMEND THE AMENDED SCOPING MEMO TO INCLUDE AN ADDITIONAL TRACK FOR EXPEDITED PROCUREMENT

Pursuant to Rule 11.1(f) of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure,[2] and as authorized by Administrative Law Judges Colin Rizzo and/or Julie A. Fitch, the California Community Choice Association[3] (CalCCA) respectfully submits this *Reply to American Clean Power-California Reply to Responses to Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement* (CalCCA Reply).

I. INTRODUCTION

On July 21, 2025, American Clean Power-California (ACP-CA) filed its *American Clean Power-California Motion to Amend the Amended Scoping Memo to Include an Additional Track*

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

[3] California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy (AVCE), Ava Community Energy (Ava), Central Coast Community Energy (CCCE), Clean Energy Alliance (CEA), Clean Power Alliance of Southern California (CPA), CleanPowerSF (CPSF), Desert Community Energy (DCE), Energy For Palmdale's Independent Choice (EPIC), Lancaster Energy (Lancaster), Marin Clean Energy (MCE), Orange County Power Authority (OCPA), Peninsula Clean Energy (PCE), Pico Rivera Innovative Municipal Energy (PRIME), Pioneer Community Energy (Pioneer), Pomona Choice Energy (Pomona), Rancho Mirage Energy Authority (RMEA), Redwood Coast Energy Authority (RCEA), San Diego Community Power (SDCP), San Jacinto Power (SJP), San José Clean Energy (SJCE), Santa Barbara Clean Energy (SBCE), Silicon Valey Clean Energy (SVCE), Sonoma Clean Power (SCP), and Valley Clean Energy (VCE).

for Expedited Procurement,[4] which seeks to amend the most recent scoping memo in this proceeding to include a new expedited procurement track separate from procurement proposed under the pending Reliable and Clean Power Procurement Program (RCPPP). On August 5, 2025, CalCCA filed its response, *California Community Choice Association's Response to American Clean Power – California Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*,[5] recommending the Commission reject the motion because it: (1) is not based on a demonstrated reliability or Renewable Portfolio Standard (RPS) need; (2) is based on unsubstantiated claims of ratepayer savings; (3) if granted, will result in a near-term procurement order that will likely result in increased market prices and cause significant market distortion at a time when load serving entities (LSE) are procuring to meet mid-term reliability (MTR), RPS, and other requirements; and (4) fails to recognize the many factors that will impact the ability of a resource to obtain investment tax credits (ITC) or production tax credits (PTC).

On August 15, 2025, American Clean Power-California (ACP-CA) filed its *Reply to Responses to Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*[6] (ACP-CA Reply). For the reasons described herein, the Commission should dismiss the ACP-CA Reply, because it:

- Mischaracterizes community choice aggregator (CCA) procurement activity;

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4 *American Clean Power-California Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*, Rulemaking (R.) 20-05-003 (July 21, 2025).

5 *California Community Choice Association's Response to American Clean Power – California Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*, R.20-05-003 (Aug. 5, 2025).

6 *American Clean Power-California Reply to Responses to Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*, R.20-05-003 (Aug. 15, 2025).

- Mischaracterizes CalCCA's July 15, 2025, comments[7] and August 5, 2025, reply comments[8] to the Reliable and Clean Power Procurement (RCPPP) ruling;[9] and
- Commits legal error in stating "a fully substantiated needs assessment is not necessary to grant the motion."[10]

II. THE COMMISSION SHOULD DISMISS ACP-CA'S MISCHARACTERIZATION THAT CCAS ARE "WAITING ON THE SIDELINES"

ACP-CA claims that LSEs, "have not demonstrated they are pursuing this procurement on their own accord for statewide load."[11] ACP-CA fails to acknowledge that such demonstrations are difficult to find in a bilateral market. However, examining the CCA solicitations issued in 2024 and 2025 reveals that developers with cluster 14 projects not yet under contract have had significant opportunities to complete a contract but have failed to do so. To state that LSEs are "waiting on the sidelines" to procure is a misleading depiction of CCA procurement efforts.

The table below demonstrates this through a list of solicitations held by CCAs in 2024 and 2025 where responses could have included projects targeted in the ACP-CA motion. CalCCA gathered this information by accessing CCA websites and through direct outreach to members. This list does not include the ongoing ability for developers to submit unsolicited offers through open offer forms,[12] or to negotiate bilaterally. Some of the solicitations in this list are currently open or very recent, clearly demonstrating active and ongoing procurement efforts, rebutting ACP-CA's claim that CCAs are "waiting on the sidelines."

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7 *California Community Choice Association's Comments on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (July 15, 2025).

8 *California Community Choice Association's Reply Comments on Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (Aug. 5, 2025).

9 *Administrative Law Judge's Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal*, R.20-05-003 (Apr. 29, 2025).

10 ACP-CA Reply, at 3.

11 *Id.* at 2.

12 *See*, for example, CEA's open offer form which allows developers to submit offers year round outside of specific solicitations: https://thecleanenergyalliance.org/solicitations/.

Table 1: 2024-2025 CCA Solicitations

CCA(S)	LAUNCH YEAR	SOLICITATION
Ava/SJCE	2024	2024 Long-Term Request for Offers (RFO)
Cal Choice[13]/ CEA	2024	Request for Proposals (RFP) for Long-Term RPS eligible renewable energy and Mid-Term Reliability (MTR) capacity
CC Power[14]	2024	2024 RFP to Procure New Clean Energy and Reliability Resources
CC Power	2024	Renewable Generation and Capacity Resource RFP
CCCE	2024	2024 Clean Energy and Reliability RFP
CEA	2024	2024 California Independent System Operator (CAISO) Cluster 14 & 15 RFP for Long-Term RPS-Eligible Renewable Energy & Capacity
CPA	2024	2024 Clean Energy and Reliability RFO
CPSF	2024	2024 Renewable Energy Supplies
DCE	2024	Renewable and Mid-Term Reliability Resources RFP
MCE	2024	Open Season 2024 - RFO; Renewables and/or Renewables Paired with Storage
OCPA	2024	2024 OCPA Long-Term RPS and Incremental Capacity
PCE	2024	2024 RFO for Renewable Energy + Storage
Pioneer	2024	January 2024 RFP for MTR Procurement
Pioneer	2024	May 2024 RFP for MTR Procurement
Pioneer	2024	September 2024 RFP for Long-Term CA RPS Eligible Renewable Energy
RCEA	2024	RFO 24-403 RFO for Local Distributed Energy Storage Resources
RCEA	2024	RFO 23-401 Request for Offers for MTR Resources
SDCP	2024	RFO for Renewable Energy and Storage Projects
SDCP	2024	Disadvantaged Communities Green Tariff (DAC-GT) Community Solar Green Tariff (CSGT) RFO
SVCE	2024	2024 Carbon Free Energy and Standalone Storage Projects RFO
CC Power	2025	Request for Information (RFI) for Geothermal Capacity Procurement
CCCE	2025	RFP for Clean Energy and Reliability
CEA	2025	FRFQ/RFP Long-Term Renewable and Low/No Emissions Energy & Capacity
CPA	2025	2025 Clean Energy and Reliability RFO
CPA	2025	2025 Power Share Program RFP (DAC-GT/CSGT)
MCE	2025	Feed-in-Tariff (on-going); Renewable Generation (1-5 MW) Paired with Storage
MCE	2025	2025 Long-Term Offer RFI; Renewables (including baseload), Renewables Paired with Storage, and/or Stand-Alone Storage
OCPA	2025	Long-term RPS and Incremental Capacity
Pioneer	2025	February 2025 RFP for Long -Term CA RPS Eligible Renewable Energy
RCEA	2025	Feed-in-Tariff
SDCP	2025	Second RFO for Solar Advantage (DAC-GT)
SDCP	2025	Local Renewable Energy and Energy Storage RFI
SDCP	2025	RFO for Clean-Firm Resources
SJCE	2025	June 2025 Long-Term Resource Request for Offers
SVCE	2025	2025 Carbon Free Energy and Storage Projects RFO

13 California Choice Energy Authority (Cal Choice) members include: AVCE, EPIC, Lancaster, PRIME, Pomona, RMEA, SJP, and SBCE.

14 California Community Power (CC Power) members include: Ava, CPSF, CCCE, PCE, RCEA, SJCE, SVCE, SCP, and VCE.

III. THE COMMISSION SHOULD DISMISS ACP-CA'S MISREPRESENTATION OF CALCCA'S COMMENTS TO THE RCPPP RULING

ACP-CA mischaracterizes statements made by CalCCA regarding the procurement of the Preferred System Plan (PSP). ACP-CA states, "CalCCA has argued that contracting additional resources to align with the 2023 PSP would be sufficient and then later argued that procuring to meet the PSP would be excessive and rejects a policy to enforce procurement to the PSP."[15] ACP-CA presents this as a contradiction when the two statements refer to separate procurement objectives: *capacity and energy sufficiency* and *cost effectiveness*. The sufficiency statement refers to CalCCA's findings that the PSP would be sufficient to meet the reliability and clean energy needs of the grid. The reference to "excessive" refers to the potential for costs to be excessive if the Commission requires procurement to exactly match the PSP. CalCCA commented that the actual costs of resources in the PSP have been higher than were estimated when developing the portfolio. Therefore, it could be expected that LSEs may not procure the exact mix of resources in the PSP because of the higher cost yet still meet reliability and clean energy needs by procuring a lower cost portfolio with comparable attributes. There is no contradiction in these statements; just the reality that what is planned does not always come to reality when actual bids from resources are received and more cost-effective alternatives are available.

IV. ACP-CA COMMITS LEGAL ERROR IN STATING "A FULLY SUBSTANTIATED NEEDS ASSESSMENT IS NOT NECESSARY TO GRANT THE MOTION"

ACP-CA states "…a fully substantiated need assessment is not necessary to grant the Motion" because "…the Commission would simply direct the IOUs to test available tax credit savings and propose contracts for further review by the Commission."[16] Whether or not a "fully

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15 ACP-CA Reply, at 4.

16 *Id.* at 3.

substantiated needs assessment"[17] is necessary for the Commission to adopt the ACP-CA Motion, the Commission must comply with the resource planning process outlined by the Public Utilities Code.[18]

Section 454.51(a) establishes the "need requirement". It requires the Commission to "[i]dentify a diverse and balanced portfolio of resources ***needed*** to ensure a reliable electricity supply that provides optimal integration of renewable energy and resource diversity in a cost-effective manner. The portfolio shall be used by the commission to establish integrated resource planning-based procurement requirements...."[19] In addition to procuring diverse and integration resources, section 454.52(a)(1)(iii) frames a process for procurement to address reliability. It requires the Commission to, "as part of the integrated planning process, assess short-term, midterm, and long-term reliability by conducting probabilistic reliability modeling, including if there is sufficient capacity available for procurement in the short term and midterm by all load-serving entities to meet their procurement requirements."

In this process, however, the Commission is bound by section 454.51(d) "to permit community choice aggregators to submit proposals for satisfying their portion of the renewable integration and diverse resources ***need*** identified in subdivision (a)."[20] Hammering home the point, section 366.2(a)(5) provides: "A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers, except where other generation procurement arrangements are expressly authorized by statute."

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[17] *Ibid*.

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

[19] Cal. Pub. Util. Code § 454.51(a) (emphasis supplied).

[20] *Id.* at § 454.51(d) (emphasis supplied).

The Legislature clearly defined a process the Commission must work through to determine whether there is a "need" for additional procurement. Critical to that process is determining the attributes needed to balance the portfolio. Authorizing procurement of resources simply because they are ITC/PTC-eligible, regardless of their portfolio need or fit, does not square with the Integrated Resource Plan's (IRP) statutory framework or the Commission's past decisions.

Even if this approach to procurement under the IRP conformed with the statutory framework, the Commission must first give CCAs the opportunity to procure these resources on behalf of their customers. With no particular need or attributes specified, however, it would be impossible to determine the portion of the procurement attributable to CCAs.

V. CONCLUSION

For all the foregoing reasons, CalCCA respectfully requests the Commission dismiss the ACP-CA Reply in its entirety.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl,
General Counsel and Chief Policy Officer
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

August 22, 2025

Pacific Gas and Electric Company

Sidney Bob Dietz II
Director
Regulatory Relations

Pacific Gas and Electric Company
300 Lakeside Drive
Oakland, CA 94612

August 28, 2025

California Public Utilities Commission
Energy Division
ED Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Subject: **Pacific Gas and Electric Company's Reply on behalf of the Portfolio Administrators to the Protest by Cal Advocates to Advice 5095-G/7664-E et al – PG&E's Filing on Behalf of the Energy Efficiency Portfolio Administrators for Goal Constructs Associated with Equity and Market Support Indicators (Pursuant to D.23-06-055, Ordering Paragraph 25)**

Dear Energy Division Tariff Unit:

Background

Pursuant to Ordering Paragraph (OP) 25 of Decision (D.) 23-06-055, Pacific Gas & Electric Company (PG&E), on behalf of the Energy Efficiency Portfolio Administrators (PAs), filed a Tier 3 Advice Letter (AL) with the California Public Utilities Commission (CPUC or Commission) on August 1, 2025. This AL contains a Report titled "Equity and Market Support Goal Constructs Report," which 1) proposed goal construct options for each segment (equity and market support), 2) recommended a process for proposing and adopting equity and market support segment goals, and 3) proposed a study scope, methods, and an associated budget to develop meaningful, measurable, and achievable goals.

Protest

The Public Advocates Office (Cal Advocates) protests the Joint AL "on the grounds that it violates Commission orders…and it fails to justify the Joint PAs' $1 million budget request."[1] More specifically, Cal Advocates protest makes several assertions, including: A) the joint AL's proposed equity segment goal constructs do not demonstrate alignment with all the objectives of the equity segment, as required by D.23-06-055, B) the proposed market support construct violates the requirements of D.23-06-055, and C) the joint AL does not justify the joint PAs' request for a $1 million budget for studies on baseline

[1] Cal Advocates' Protest, p. 2.

metrics, data collection methods, and recommendations for goal implementation and tracking.

Response

While the PAs categorically respond below in Sections A through C to the three key points raised by Cal Advocates, the PAs assert that the Joint AL complies with both the letter and the intent of OP 25. The filing presents multiple goal construct options for each segment, identifies a process for quantifying and operationalizing goals, and sets aside the required $1 million budget to fund the study that will provide baselines and targets. OP 25 does not require quantified goals at this stage[2]; rather it requires a framework that can later be developed into measurable goals through further Commission-guided study.

The Joint AL also respects the Commission's intent and direction in three important ways:

1. It proposes options for overarching constructs rather than attempting to force a one-to-one mapping with each segment objective, consistent with Commission direction.
2. It recognizes that goal constructs may be set at different geographic or administrative levels (statewide, by territory, or by PA), providing essential flexibility while ensuring consistency through the study process.
3. It follows the Commission's directive to set aside $1 million from EM&V funds as a cap for the required study, acknowledging that the final budget and scope will be determined later.

As clarified in Resolution E-5351 Recommendation 1, part 4, the purpose of Equity and Market Support Indicators and Metrics includes supporting the "Development and execution of goals for Equity and Market Support Segments."[3] The Commission limited the requirement in OP 25 to "two or three" goal constructs per segment, recognizing that a manageable set of illustrative options was necessary at this early stage. While OP 25(b) lists multiple descriptive elements by which a construct may be characterized — such as alignment with objectives, identification of metrics, or consideration of statewide versus PA-level goals — Resolution E-5351 outlines guidance criteria in Recommendation 1 as the purpose, not cumulative requirements, that must all be fully satisfied within each construct. The Commission's intent was to provide a framework that could later be tested, refined, and quantified through the EM&V study, rather than to require an exhaustive mapping of every objective at this initial step.

[2] D.23-06-055, pp. 69–71 (Discussion of developing Market Support and Equity goals; process for subsequent studies).
[3] Resolution E-5351 (Clarification and revisions to adopted indicators and metrics related to energy efficiency portfolios in compliance with Decision (D.) 23-06-055), p. 6.

A. Equity Goal Construct Alignment with Objectives Required by D.23-06-055

Cal Advocates asserts that the Equity Goal Constructs should be rejected as they do not address *all* (emphasis added) four objectives identified in D.23-06-055.[4] However, it's the Joint PA's understanding that D.23-06-055 did not require the goal constructs to address all four objectives in this advice letter. Rather, these four are examples of the type of objectives that could be used to develop the goal constructs rather than an absolute requirement to address all four. As it stands, both E-1 (Categorical Equity Target Participation) and E-2 (Percent of Equity Target Participants in the Portfolio) address Objective 1 (i.e., Address disparities in access to EE programs). Furthermore, E-3 (Equity Target Bill Savings) addresses the "energy affordability" of Objective 2 (i.e., Promote resilience, health, comfort, safety, energy affordability, and/or energy savings).

It's important to note that OP 25(b) of D.23-06-055 ordered the PAs to define "…options for two or three goal constructs each for market support and equity segments…,"[5] which called for a limited number of goal construct options to be advanced. If the Commission had intended the goal constructs to exhaustively address all four objectives, then sub-section 25(b) would have presumably requested a greater number of goal constructs or would not have placed a limit on the number of goal constructs.

While Cal Advocates' interpretation and those of the Joint PAs might differ on the comprehensiveness of the objectives at this time, it is reasonable that a limited number of goal constructs should be studied for this first undertaking with the possibility of developing additional goal constructs in the future.[6] Because of the novel nature of establishing goals for the equity segment, the first attempt should not be overly complicated and the learnings from this process can be used to develop additional goal constructs and related goals in the future.

B. Market Support Construct Two's Adherence to Requirements of D.23-06-055

Cal Advocates asserts that Market Support Two (PA Determined Market Needs) violates the requirement of D.23-06-055, as the Decision did not provide flexibility for PAs to establish their own goal constructs. The primary citation[7] provided by Cal Advocates for

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[4] D.23-06-055 pp.57-58 lists the following four objectives: 1) address disparities in access to EE programs; 2) promote resilience, health, comfort, safety, energy affordability, and/or energy savings; 3) reduce energy-related greenhouse gas and criteria pollutant emissions; and 4) provide workforce opportunities.

[5] D.23-06-055, p. 126.

[6] D.23-06-055, p. 71: It is our intention that a goals development process for the market support and equity segments will follow a timeline that aligns goals adoption to the next portfolio cycle beginning in 2028. The Tier 3 advice letter will address the process for setting the goals, including annual targets, goal metrics, and forecast values. Market support and equity goals are ultimately expected to be long-term, broken into four-year increments, and will begin in 2028.

[7] Cal Advocates protest in footnote 32.

such a prohibition points to OP 25(b). However, OP 25(b) does not state any prohibition of PA-specific goals. On the contrary, OP 25(b), sub-section (iii), contemplates PA specific goals where it states "Whether goals should be set statewide, by territory, or by *portfolio administrator.*"[8]

The Joint PAs respectfully disagree with Cal Advocates' assertion that "Allowing individual PAs to establish goal metrics and indicators unique to their programs and territories would…frustrate the Commission's ability to track and compare PA performance and portfolio success in achieving EE goals."[9] A uniform, one-size-fits-all approach would hinder each PA's ability, particularly RENs and CCAs to effectively respond to the distinct needs of their participants and communities. This perspective overlooks the critical importance of flexibility and responsiveness in program design. A tailored approach empowers each PA to deliver meaningful, locally responsive energy efficiency solutions while still aligning with statewide goals.

C. Justification for the $1 Millon Budget

The Joint PAs clarify that the $1 million set-aside required by OP 25 is viewed simply as a budgetary cap.[10] The actual study scope and budget can be determined only after the Commission selects, and possibly clarifies, specific construct options, ensuring efficient use of ratepayer funds. There is no assumption that all $1 million that is authorized will be used for this study. Furthermore, the IOU PAs, as communicated in the Advice Letter, proposed to jointly fund the work instead of having all 12 PAs co-fund to simplify the process thereby potentially reducing administration cost.

The Joint PAs agree with Cal Advocates that authorized funds must be used in a "just and reasonable"[11] manner. There is a shared PA expectation that the authorized funds will be used in a prudent manner.

Conclusion

The Joint PAs assert that Advice 5095-G/7664-E et al. satisfies the requirements of OP 25 and should be adopted by the Commission as filed The PAs appreciate the ability to respond to this protest.

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[8] D. 23-06-055, p.126.
[9] Cal Advocates protest, p. 5.
[10] D.23-06-055, OP 25, p. 126; see also p. 162 (EM&V budget set-aside).
[11] Cal Advocates' protest, p. 6.

Sincerely,

/S/

Sidney Bob Dietz II
Director, Regulatory Relations
CPUC Communications

cc: Shelly Lyser, Public Advocates Office
James Ahlstedt, , Public Advocates Office
Service Lists A.22-02-005 and R.25-04-010