MAY FILINGS

California Community Choice Association

SUBMITTED 05/10/2024, 04:08 PM

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

1. **Please provide your feedback and perspectives on the value and need for Fast Start Pricing within ISO markets, including perspectives on the Fast-Start Pricing analysis provided in Working Group Session #16.**

   The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the fast-start pricing analysis presented in working group #16. The analysis is helpful for understanding the impact of fast-start pricing on market prices, including seasonal trends, daily trends, and locational trends. The California Independent System Operator's (CAISO) analysis demonstrates that fast-start pricing could impact the price in up to 25 percent of the intervals and, under extreme summer and gas conditions, up to a monthly average of $8.70 per megawatt-hour. While this analysis is helpful for understanding the cost impacts of fast-start pricing, discussions in the working group have not demonstrated sufficient benefits associated with fast-start pricing to justify these cost increases.

   The CAISO has other mechanisms for ensuring fast-start resources recover their costs without the customer cost impacts associated with fast-start pricing. The CAISO compensates fast-start resources for their start-up costs outside the market rather than in the locational marginal price. Under fast-start pricing, fast-start resources' total compensation would remain the same, but the market clearing price would rise to include start-up costs and award that higher price to all resources that clear the market.

   The CAISO, the Department of Market Monitoring, and stakeholders have raised a series of concerns with fast-start pricing within the Federal Energy Regulatory Commission Notice of Proposed Rulemaking in Docket RM17-3 and within the Price Formation Enhancements Working Groups thus far. These concerns stem from the fact that elements of the CAISO's market, like the flexible ramping product, make it unique from other independent system operators' or regional transmission organizations' markets, and are incompatible with fast-start pricing. Fast-start pricing would undermine the CAISO's efforts to procure flexible resources in real-time, result in infeasible dispatches, and weaken price signals to provide ramping capability when coupled with the flexible ramping product. The CAISO should not ignore these concerns in favor of implementing a seemingly unnecessary pricing structure that would increase customer costs for an unclear benefit.

   For these reasons, CalCCA continues to oppose the implementation of fast-start pricing in the CAISO's market unless any perceived benefits associated with the costs of fast-start pricing can be clearly articulated and quantified.

2. **Please provide your organizations level of priority (High, Medium, Low) as it relates to further policy development for Fast-Start Pricing.**

   Fast-start pricing is a low priority for CalCCA. For the reasons described in Section 1, the CAISO should not move forward with developing fast-start pricing for its markets.

3. **Please provide any additional feedback.**

   CalCCA has no additional feedback at this time.

California Community Choice Association

SUBMITTED 05/17/2024, 03:54 PM

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

1. Provide a summary of your organization’s overall comments on the April 29-30 RAMPD Hybrid Stakeholder Working Group and Updated Discussion Paper & Draft Recommendation Plan:

1. **Recommendation Plan:**

The California Community Choice Association (CalCCA) appreciates the opportunity to comment on the April 29-30, 2024, Resource Adequacy Modeling and Program Design (RAMPD) Working Group (WG) and the Updated Discussion Paper and Draft Recommendation Plan (Discussion Paper). These comments recommend that the California Independent System Operator Corporation (CAISO) move forward with the policy development phase for track 1, track 2, and track 3. These comments also provide recommendations on the backstop and Extended Day-Ahead Market (EDAM) resource sufficiency evaluation (RSE) issues discussed in the working groups. In summary:

- The process for defining the Capacity Procurement Mechanism (CPM) Soft Offer Cap (SOC) works as intended, covering going-forward fixed costs of the marginal resources on the system and mitigating market power.
- The CAISO should not revise the CPM SOC to be reflective of bi-lateral prices, as bi-lateral prices currently do not reflect cost, they reflect scarcity.
- The CAISO’s current cost allocation mechanism generally works well and as intended by allocating costs first to entities that caused the need for backstop before allocating costs broadly to all load-serving entities (LSE).
- Any examination of using a different proxy unit as the basis for the CPM SOC, should consider the following: (1) thermal units are still the most likely units to receive CPMs, (2) the costs of alternative proxy units are likely not higher than the costs of thermal units, and (3) generators have the option to demonstrate higher costs to bid a higher CPM price.
- If the CAISO is going to consider an assessment for energy sufficiency, and if there is a need to procure for lack of energy sufficiency, then the CAISO would also need to examine how to allocate backstop costs in a manner that reflects causation.
- The CAISO should consider if there is a need to develop an EDAM RSE failure cure mechanism that allows for the procurement of capacity that more closely matches the need.
- Any evaluation of allocating RSE failure costs consistent with cost causation must recognize that LSE Resource Adequacy (RA) positions are not the only cause of RSE shortfalls.
- The CAISO should not move forward with stakeholder suggestions to move to 100 percent annual showings or to include planned outages into RA requirements.

2. Provide your organization’s feedback on the ISO’s April 29th presentation on backstop and the backstop panel discussion:

CalCCA appreciates the opportunity to participate in the robust panel discussion on the CAISO’s backstop mechanism and reiterates its responses to the panel questions here:

1. What challenges (if any) have you observed with the CAISO’s current backstop processes?

During the WG, the CAISO indicated that one challenge with the current CPM process is that the CAISO only has access to shown RA capacity and competitive solicitation process (CSP)

offers as CPM capacity, and its access to CPM capacity has declined over the last five years due to a decline in CSP offers. This challenge is not a function of the way the CAISO’s current backstop processes are designed but rather a function of the current lack of capacity that has RA market prices unprecedentedly high. In a market with prices going through the roof, it is likely that generators can sell their capacity to LSEs at much higher prices than the CPM SOC because LSEs are competing for scarce supply to meet their compliance obligations. This does not signal a need to change the current CPM process as it relates to the SOC. The process for defining the SOC works as intended, covering going-forward fixed costs of the marginal resources on the system and mitigating market power.[1] It is not intended to be competitive with bi-lateral market prices, which currently reflect market scarcity rather than resources' costs.

2. Do the current mechanisms (including cost allocation) work well 1. in incenting LSEs to procure sufficient capacity to meet the LRA and CAISO requirements and 2. Allowing the CAISO to obtain needed capacity (in a reasonably efficient manner) when and where needed?

Apart from the issue CalCCA has flagged previously around the treatment of allocated DR credits,[2] the CAISO's current cost allocation mechanism works well and as intended by allocating costs first to entities that caused the need for backstop before allocating costs broadly to all LSEs. The risk of CPM cost allocation is not the primary incentive for ensuring LSEs procure sufficient capacity to meet RA requirements. It is the Local Regulatory Authority (LRA) requirements, and the penalties associated with missing those requirements that are the primary drivers for LSEs procuring sufficient capacity. The California Public Utilities Commission (CPUC) penalties are extremely stringent, with financial penalties of up to $26.64 per megawatt-hour and non-financial penalties that prohibit some LSEs from expanding. CPM cost allocation based on causation adds to these incentives but is not, and need not, be the primary driver of LSEs meeting their compliance obligations.

As described in response to question 1, high RA capacity prices mean that resources are unlikely to be available as a CPM. However, if there is insufficient capacity at the current high market prices, it is unlikely the CAISO would have a better chance at obtaining capacity than LSEs would. Resources would generally prefer to sell to LSEs at high market prices than wait for a CPM offer.

3. Some have suggested in past CPM discussions raising the soft offer cap either, 1. to reflect the opportunity costs to sell outside of the CAISO, or 2. to reflect the costs of a different proxy unit (e.g. the all-in cost of combined solar plus storage). What impact would such an increase in the soft offer cap have on the bilateral market?

Any examination of using a different proxy resource to calculate the CPM SOC should consider the following:

- The CPM SOC has generally been set to impact the likely unit to receive the CPM serving to ensure that they can recover expected costs. Historical data and regulatory requirements suggest that CPM capacity is likely to continue to be gas resources. 66 percent of CPMs since 2019 have come from gas units and no CPMs have come from hybrid resources. Because most renewable and hybrid resources are under contract for Integrated Resource Plan and Renewable Portfolio Standard regulatory requirements, and therefore also contracted for RA, it would not be expected for non-thermal resources to be regularly available for CPM.

- The California Energy Commission report establishing the cap includes, (1) insurance; (2) ad valorem taxes; and (3) fixed operations and maintenance (O&M). It is difficult to imagine that those costs for another resource type are much different than the value used for the current SOC. In fact, it seems reasonable to assume that the fixed O&M for a hybrid may very well be lower. Studies on the fixed O&M are split on how they treat battery degradation with some ascribing it to fixed O&M while others ascribe all of it to variable O&M. It is worth noting that the CAISO process for developing default energy bids for battery storage does include battery degradation as part of its calculation supporting that at least some of the cost is variable O&M.
- Finally, the cap is a soft offer cap. Therefore, if a generator has a cost that it can demonstrate is higher than the SOC, that generator can ask the Federal Energy Regulatory Commission (FERC) to allow it to bid into the CSP at a price sufficient to cover its cost. To date, the CAISO has not published information that confirms any generator has made such a request to the FERC.

As discussed in the sections above, the bilateral capacity market is in turmoil. RA market prices currently do not appear to be based on cost but rather on whatever buyers will pay. Under these conditions, sellers will search for any available opportunity cost signal and, therefore, what price they can offer. Changes to the CAISO SOC will provide such a signal. Because markets should function competitively, and the SOC is a market power mitigation mechanism, the CAISO should set the CPM SOC to reflect cost, as it does in energy markets with default energy bids. The soft-offer cap already does this and provides an opportunity to get a higher payment if a higher cost can be proven at the FERC.

4. How should we consider the evolving resource mix (with an increased reliance on storage in particular) impacting our backstop processes? For example, should the CAISO BA's have an assessment for energy sufficiency?

The CPUC's RA program has already taken steps to consider the evolving resource mix through its slice-of-day (SOD) framework. Once implemented, LSEs will need to provide 24 hourly showings for each month. This should ensure CPUC-jurisdictional LSEs bring enough RA capacity to ensure energy sufficiency. If the CAISO is going to consider an assessment for energy sufficiency, and if there is a need to procure for lack of energy sufficiency, then the CAISO would also need to examine how to allocate backstop costs in a manner that reflects causation.

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[1] The CAISO lists these as the two objectives of the soft offer cap in the Discussion Paper at 12-13. CalCCA agrees with these objectives.

[2] CalCCA Working Group Comments (Jan. 30, 2024): https://stakeholdercenter.caiso.com/Comments/AllComments/97779f5e-e0a7-4b0f-ad97-855c6cc08ead#org-fe78f059-eae0-4c19-ad57-f3767aa36546.

3. Provide your organization's comments on the April 29th Projected EDAM RSE Shortfalls discussion:

The CAISO proposes to use its existing exceptional dispatch authority to address potential EDAM RSE shortfalls. The challenge with using exceptional dispatch CPMs is that the minimum CPM term does not align with the likely term of an RSE failure. The minimum term for an exceptional dispatch CPM is 30 days, while RSE failures may be as short as an hour. Other Balancing Authorities can and will be able to make capacity procurement on shorter intervals to meet RSE failures. While the CAISO would like to cure RSE failures in California, it should not place the LSEs in California at a competitive disadvantage. When the CAISO has the potential to procure CPM capacity for a 30-day term to solve a one-hour RSE shortfall, it is unclear if using CPM is more cost-effective than not curing the RSE shortfall. The CAISO should consider if there is a need to develop a mechanism that allows for the procurement of capacity that more closely matches the need.

Regarding the allocation of RSE failure costs, any evaluation of whether costs can be allocated consistent with cost causation must recognize that LSE RA positions are not the only cause of RSE shortfalls. Many factors can contribute to an RSE failure, some of which may not be related to RA positions. For example, if an RA resource goes on outage and does not provide substitution, it is a resource availability problem rather than an LSE RA position problem. If an RSE failure is caused by short RA positions, the CAISO would need to first evaluate each LRA program before allocating costs to individual LSEs since the types of capacity and their ability to meet hourly needs can differ. Many complex questions must be considered to adopt a cost allocation methodology consistent with cost causation.

4. Provide your organization's feedback on the proposed Track 1: Modeling and Default Standards as reflected in the Updated Discussion Paper & Draft Recommendation Plan:

Do you have suggested recommendations on the scope of the track, problem statement, process, interdependencies or general recommendations on the path forward?

This problem statement is ready to move forward to policy development. The CAISO should consider the issues described in its December 20, 2023, comments,[1] when it considers this issue in the policy development phase.

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[1] https://stakeholdercenter.caiso.com/Comments/AllComments/1aafa171-55d2-4e71-869e-f2b78a0718c9.

5. Provide your organization's feedback on the proposed Track 2: Outage and Substitution and RAAIM Reform as reflected in the Updated Discussion Paper & Draft Recommendation Plan:

Do you have suggested recommendations on the scope of the track, problem statement, process, interdependencies or general recommendations on the path forward?

This problem statement is ready to move forward to policy development. The CAISO should consider the issues described in its March 27, 2024, comments [1] and its February 27, 2024, comments[2] when it considers this issue in the policy development phase.

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[1] https://stakeholdercenter.caiso.com/Comments/AllComments/a79881e1-374a-4d13-aa17-cbbf7e631b3a#org-6b240e6d-295e-4f19-9bf2-280896d7b4a4.

[2] https://stakeholdercenter.caiso.com/Comments/AllComments/1ab40647-72b9-4f6d-9303-961b8e78762c#org-faf0dd08-d824-4f32-894d-b5b510d3f3a8.

6. Please provide your organization's feedback on the problem statement for Track 3: Backstop Mechanisms, and assessment on if it is ready to move forward to the policy development process. Do you agree that certain parts or all of the problem statement is ready to move forward for policy development? If not, please describe which elements of the problem statement is incomplete or inaccurate, and provide your suggested edits and additional information, changes and/or analysis required to move forward.

Problem statement details: (1) The ISO lacks visibility into the contract and availability status of resources not shown as RA, preventing the ISO from efficiently and reliably running its current CPM processes; (2) Stakeholder feedback is that there is a lack visibility into the ISO's CPM decision making processes; (3) In the current tight RA market, the ISO's Capacity Procurement Mechanism may not be producing all of its intended results particularly given the frequent lack of bids into its Competitive Solicitation Processes; (4) As the reliability needs evolve (e.g. to address changing needs for battery storage) the ISO's CPM process may need to evolve to obtain specific attributes necessary for reliability.

This problem statement is ready to move forward to policy development. The CAISO should consider the comments in section 2 when it considers this issue in the policy development phase.

7. Please provide your organization's feedback on the problem statement for Track 4: Day Ahead Sufficiency in EDAM for the ISO BAA and assessment on if it is ready to move forward to the policy development process. Do you agree that the problem statement is ready to move forward for policy development? If not, please describe why the problem statement is incomplete or inaccurate, and provide your suggested edits and additional information and analysis required to move forward:

Problem statement details: While CAISO proposes to utilize its existing exceptional dispatch authority to resolve reliability concerns highlighted by potential capacity shortages identified by the RSE, stakeholders have expressed concern that: (1) The option to exceptionally dispatch resources might not be available during critical periods; (2) The cost allocation should be reexamined to align better with cost causation, if feasible.

This problem statement is ready to move forward to policy development. The CAISO should consider the issues raised in section 3 when it considers this issue in the policy development phase.

8. Provide your organization's comments on remaining topics for Future Working Groups, including flex RA, energy sufficiency, deliverability, and interoperability with existing and

emerging RA programs:**

CalCCA has no comments at this time but will provide comments when the CAISO brings these topics to the working group.

9. **Provide your organization's feedback on the Track 5 table of stakeholder suggestions in the Updated Discussion Paper & Draft Recommendation Plan (pgs. 17-18). Are there any that you believe should be incorporated into one of the existing proposed tracks for policy development or that deserves its own policy development process?**

For the reasons described in its March 27, 2024, comments,[1] the CAISO should not move forward with stakeholder suggestions to move to 100 percent annual showings or to include planned outages into RA requirements.

The CAISO should also take caution when evaluating stakeholder suggestions for the CAISO to backstop if it has not met a 0.1 loss of load expectation. LRAs set their RA requirements to meet planning standards. If the CAISO sets a different target than the LRA, LSEs would be subject to two different requirements. Additionally, because each LRA's RA program is different, the CAISO would need to assess each LRA's contribution to reliability before allocating backstop costs to LSEs. LRAs should be responsible for ensuring their programs are set up to meet planning standards.

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[1] https://stakeholdercenter.caiso.com/Comments/AllComments/a79881e1-374a-4d13-aa17-cbbf7e631b3a#org-6b240e6d-295e-4f19-9bf2-280896d7b4a4.

10. **Please provide any additional comments not captured above:**

CalCCA has no additional comments at this time.

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

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

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

Utility type:
- ☑ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Amulya Yerrapotu
Phone #: 415-464-6664
E-mail: ayerrapotu@mcecleanenergy.org
E-mail Disposition Notice to: ayerrapotu@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE

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

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 76-E

Tier Designation: 2

Subject of AL: Approval of Amendments to MCE's Disadvantaged Communities Green Tariff Program 2023 Power Purchase Agreements

Keywords (choose from CPUC listing): COMPLIANCE

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.18-06-027, E-5124

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

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

Confidential treatment requested? ☑ Yes ☐ No

If yes, specification of confidential information: MCE is seeking confidential treatment for Attachments A, B, C,
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? ☐ Yes ☑ No

Requested effective date: 6/19/24

No. of tariff sheets: 0

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

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

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

Tariff schedules affected: N/A

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

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

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

Clear Form

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

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Amulya Yerrapotu
Title: Policy Associate
Utility/Entity Name: Marin Clean Energy

Telephone (xxx) xxx-xxxx: 415-464-6664
Facsimile (xxx) xxx-xxxx:
Email: ayerrapotu@mcecleanenergy.org

Contact Name: MCE Regulatory
Title: Regulatory Account
Utility/Entity Name: Marin Clean Energy

Telephone (xxx) xxx-xxxx: N/A
Facsimile (xxx) xxx-xxxx: N/A
Email: regulatory@mcecleanenergy.org

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

Clear Form

ENERGY Advice Letter Keywords

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

Clear Form

MCE | My community. My choice.

MARIN COUNTY | NAPA COUNTY | UNINCORPORATED CONTRA COSTA COUNTY | UNINCORPORATED SOLANO COUNTY
BENICIA | CONCORD | DANVILLE | EL CERRITO | FAIRFIELD | LAFAYETTE | MARTINEZ | MORAGA | OAKLEY
PINOLE | PITTSBURG | PLEASANT HILL | RICHMOND | SAN PABLO | SAN RAMON | VALLEJO | WALNUT CREEK

May 20, 2024

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

ADVICE LETTER MCE 76-E

RE: Approval of Amendments to MCE's Disadvantaged Communities Green Tariff Program 2023 Power Purchase Agreements

Pursuant to Decision ("D.") 18-06-027[1] and Resolution E-5124,[2] Marin Clean Energy ("MCE") hereby submits this Tier 2 Advice Letter ("AL") for approval of Amendment No. 3 to two Power Purchase Agreements ("PPAs") between MCE and CES Electron Farm One, LLC ("Seller"), which resulted from MCE's initial Disadvantaged Communities Green Tariff ("DAC-GT") Request for Offers ("RFO"). Attached to this AL are:

Attachment A: Amendment No. 3 to the Renewable PPA between MCE and CES Electron Farm One, LLC, dated as of May 3, 2024 ("Conflitti PPA 1")

Attachment B: Amendment No. 3 to the Renewable PPA between MCE and CES Electron Farm One, LLC, dated as of May 3, 2024 ("Conflitti PPA 2")

Attachment C: 2022 DAC-GT and CS-GT RFO Bid Information

Attachment D: 2024 MCE Open Season - Small Scale Stand-Alone Solar Offers

Attachment E: 2023-2024 MCE Comparable Amendments

Attachment F: Confidentiality Declaration

TIER DESIGNATION

This AL has a Tier 2 designation pursuant to Ordering Paragraph ("OP") 8 of Resolution E-5124.

[1] See. D.18-06-027 at pp. 87-88, approving CCA participation in DAC-GT and CS-GT.
[2] Resolution E-5124, Ordering Paragraph 8.

EFFECTIVE DATE

Pursuant to G.O. 96-B, MCE requests that this Tier 2 AL become effective on June 19, 2024, which is 30 calendar days from the date of this filing.

CONFIDENTIALITY TREATMENT

MCE is seeking confidential treatment for Attachments A, B, C, D, and E to this AL. The information for which MCE is seeking confidential treatment is identified in the Confidentiality Declaration in Attachment F. A public version of this AL and its attachments is being served on the service list for R.14-07-002 and A.16-07-015, as described below.

BACKGROUND

On June 21, 2018, the California Public Utilities Commission ("Commission" or "CPUC") approved D.18-06-027, adopting two new community solar programs to promote the use of renewable generation among residential customers in disadvantaged communities ("DACs"),[3] as directed by the California Legislature in Assembly Bill ("AB") 327 (Perea), Stats. 2013, ch. 611. The DAC-GT and the CS-GT programs offer 100% solar energy to eligible customers and provide a 20% discount on the electric portion of the bill.

D.18-06-027 allows Community Choice Aggregators ("CCAs") to develop their own DAC-GT and CS-GT programs, and states that CCAs that elect to offer DAC-GT and CS-GT must abide by all rules and requirements adopted in that decision.[4] Pursuant to OP 17 of D.18-06-027, MCE filed its Implementation AL (MCE AL 42-E) on May 7, 2020. The Commission approved AL 42-E in Resolution E-5124, issued April 15, 2021.

MCE issued its initial DAC-GT and CS-GT RFO on August 27, 2021, and accepted bids through November 19, 2021. MCE executed the two Conflitti PPAs with Seller on March 20, 2022. In accordance with Resolution E-5124, MCE submitted Advice Letter 63-E to the Commission on June 20, 2022 seeking approval of the Conflitti PPAs. Advice Letter 63-E was approved by the Commission via a disposition letter on July 20, 2022, with an effective date of June 20, 2022.

MCE received Board approval on October 6, 2023 to execute one material, commercial amendment to both the Conflitti 1 PPA and Conflitti 2 PPA.[5] In exchange for the negotiated price increase and commercial operation date extension of the amendment, MCE negotiated that the developer must pursue the new Low Income Investment Tax Credit ("ITC") Bonus. If the developer can obtain the Low Income ITC bonus, then the price increase will be negated.

[3] DACs are defined under D.18-06-027 as communities that are identified in the most current version of CalEnviroScreen as among the top 25 percent of census tracts statewide, plus the census tracts in the highest five percent of CalEnviroScreen's Pollution Burden that do not have an overall CalEnviroScreen score because of unreliable socioeconomic or health data. For purposes of this AL, MCE is using CalEnviroScreen 3.0, which was the current version at the time of the solicitation described herein.
[4] D.18-06-027, p. 104, OP 17.
[5] On June 17, 2022, MCE executed a non-material, non-commercial amendment to both PPAs to state explicitly the language of the RPS non-modifiable standard terms and conditions.

MCE submitted Advice Letter 71-E to the Commission on October 25, 2023 seeking approval of the amendments. The CPUC approved the amendments on January 31, 2024 with an effective date of November 24, 2024.

Shortly after Board approval of the second amendments, in October of 2023, Seller approached MCE to propose revisions to certain commercial terms in the contracts. MCE and Seller negotiated and modified terms to the Conflitti PPAs, which are included in the Amendments provided as part of this Advice Letter. On May, 3, 2024, MCE's Board granted approval to execute another material, commercial amendment to both the Conflitti 1 PPA and Conflitti 2 PPA to address the need for (1) a price increase and (2) an extension of the expected start of construction and commercial operation dates. The section below explains the rationale for the Amendments.

SUMMARY OF AMENDMENT PROCESS

After approval of the second amendments, Seller notified MCE that it would be unable to perform under the requirements of Conflitti PPA 1 and 2. After approval of the second amendments, the counterparty believed they had arranged a firm financing package, but this arrangement was not realized as anticipated. Seller attempted to go back out to the market to secure sufficient financing, but learned that current financing options did not support the continuation of the projects at the current PPA rate. Seller indicated that without the negotiated price increase, it would be unable to perform under Conflitti PPA 1 and 2. MCE negotiated this Third Amendment that grants a price increase and further extension to complete construction of both facilities.

MCE has performed due diligence with respect to the proposed amendments. MCE confirmed that Seller's requested price increase is below the Commission-determined price cap for DAC-GT projects. Seller's requested price increase is competitive with bids received by MCE for its 2021 DAC-GT RFO. The increased contract price requested by Seller is in line with contract prices in all other offers MCE received in the 2021 DAC-GT solicitation, which is supported by the information provided in Attachment C. If the Conflitti PPAs were to be cancelled, MCE would need to go back out to market to fill its capacity for the DAC-GT program. As demonstrated in Attachment D, the comparable project bid MCE received in its 2024 Open Season solicitation was priced consistently with the Conflitti PPAs when including the Investment Tax Credit ("ITC") and slightly more than the Conflitti PPAs when not including the ITC. MCE determined it would be prudent and reasonable to accept the price increase and avoid the administrative cost of going back out to market as well as the higher anticipated price of offers. Finally, as supported by Attachment E, MCE determined that the overall requested price increase in PPA amendments 2 and 3 is in line with the only other PPA amendment granted in 2023-2024.

MCE's Board of Directors reviewed the negotiated amendments to the Conflitti PPAs during its May 3, 2024 Technical Committee meeting and approved the execution of the Amendments.

NOTICE

Anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be mailed to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

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

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

Amulya Yerrapotu
Policy Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Ave.
San Rafael, CA 94901
ayerrapotu@mcecleanenergy.org

MCE Regulatory
regulatory@mcecleanenergy.org
MARIN CLEAN ENERGY
1125 Tamalpais Ave.
San Rafael, CA 94901
Phone: (415) 464-6676

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

MCE is serving copies of this advice filing to the relevant parties shown on the R.14-07-002 and A.16-07-015 service list(s). For changes to these service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

CORRESPONDENCE

For questions, please contact Amulya Yerrapotu by electronic mail at ayerrapotu@MceCleanEnergy.org.

/s/ Amulya Yerrapotu
Amulya Yerrapotu
Policy Analyst
MARIN CLEAN ENERGY (MCE)

cc: R.14-07-002 Service List
A.16-07-015 Service List

ATTACHMENT A

THIRD AMENDMENT TO
DISADVANTAGED COMMUNITIES GREEN TARIFF (DAC-GT) RENEWABLE POWER PURCHASE AGREEMENT

This **THIRD AMENDMENT TO DISADVANTAGED COMMUNITIES GREEN TARIFF (DAC-GT) RENEWABLE POWER PURCHASE AGREEMENT** (this "Amendment") effective as of May 3, 2024 ("Effective Date"), is made between CES Electron Farm One, LLC ("Seller") and Marin Clean Energy, a California joint powers authority ("MCE" or "Buyer"). Seller and Buyer are referred to individually as a "Party" or collectively as the "Parties".

RECITALS

WHEREAS, the Parties entered into that certain Disadvantaged Communities Green Tariff (DAC-GT) Renewable Power Purchase Agreement, dated March 20, 2022, as amended on June 17, 2022 and as further amended on October 13, 2023 (the "Agreement"); and

WHEREAS, the Parties desire to amend the Agreement on the terms and conditions contained herein.

AGREEMENT

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, as well as the mutual covenants and agreements herein contained, the Parties agree as follows:

1. **Amendments to the Agreement.**

(a) Cover Sheet, the Expected Construction Start Date is deleted and replaced with "12/31/2024"

(b) Cover Sheet, the Expected Commercial Operation Date is deleted and replaced with "3/31/2026".

(c) Cover Sheet, the Contract Price is deleted and replaced with "[redacted]".

2. **General.**

a. Agreement Otherwise Not Affected. Except as expressly modified as set forth herein, the Agreement remains unchanged and, as so modified, the Agreement shall remain in full force and effect.

b. Entire Agreement. This Amendment constitutes the entire agreement and understanding of the Parties with respect to its subject matter and supersedes all oral communication or prior writings related thereto.

c. Binding Effect. This Amendment shall be binding upon, inure to the benefit of and be enforceable by the Parties hereto and their respective successors and assigns.

d. Governing Law. THIS AMENDMENT SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF CALIFORNIA, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW. TO THE EXTENT ENFORCEABLE AT SUCH TIME, EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS AMENDMENT.

e. Counterparts. This Amendment may be executed in any number of counterparts, each of which when so executed and delivered shall be deemed to be an original and all of which taken together shall constitute but one and the same agreement. Delivery of an executed signature page of this Amendment as a PDF attachment to an email shall be the same as delivery of a manually executed signature page.

f. Reservation of Rights. Each of the Parties expressly reserves all of its respective rights and remedies under the Agreement.

[*Signatures appear on the following page.*]

IN WITNESS WHEREOF, the Parties hereto have caused this Amendment to be duly executed as of the Effective Date.

CES Electron Farm One, LLC

Sign: Michael Kremer
Name: Michael Kremer
Title: Authorized Person

Marin Clean Energy, a California joint powers authority

DocuSigned by:
Sign:
Name: Devin Murphy
Title: Technical Committee Chair

Marin Clean Energy, a California joint powers authority

DocuSigned by:
Sign: Dawn Weisz
Name: Dawn Weisz
Title: CEO

ATTACHMENT B

THIRD AMENDMENT TO DISADVANTAGED COMMUNITIES GREEN TARIFF (DAC-GT) RENEWABLE POWER PURCHASE AGREEMENT

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[*Signatures appear on the following page.*]

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CES Electron Farm One, LLC

Sign:
Name: Michael Kremer
Title: Authorized Person

Marin Clean Energy, a California joint powers authority

DocuSigned by:
Sign:
Name: Dev[illegible]phy
Title: Technical Committee Chair

Marin Clean Energy, a California joint powers authority

DocuSigned by:
Sign: Dawn Weisz
Name: Dawn Weisz
Title: CEO

ATTACHMENT C

2021 DAC-GT RFO Bid Information

Developer	**Project Name**	**Capacity (MW)**	**Technology**	**Energy Price ($/MWh)**
White Pine Development, LLC	Conflitti	4.4	PV	[redacted]
Renewable America, LLC	Dos Palos Clean Power	3	PV	[redacted]
Renewable America, LLC	Oroville Dam Clean Power	2	PV	[redacted]

ATTACHMENT D

2024 MCE Open Season - Stand-Alone Small Scale Solar Bid Information

Developer	Project Name	Capacity (MW)	Technology	Energy Price ($/MWh)
Renewable America, LLC	King Kettle Clean Power I – ITC Cat1	5	PV	[redacted]
Renewable America, LLC	King Kettle Clean Power I – ITC No Cat1	5	PV	[redacted]

ATTACHMENT E

2023-2024 MCE PPA Energy Price Adjustment Amendments

Developer	Project Name	Capacity (MW)	Technology	Energy Price Change ($/MWh)
Golden Fields Solar IV, LLC (owner Clearway)	Golden Fields	100 MW Solar (with 92 MW Battery Storage)	PV and Battery Storage	[redacted]*

* The storage price for this PPA also increased. This advice letter provides only the energy price increase to allow for a more accurate comparison to the Conflitti project.

ATTACHMENT F

Declaration of Dawn Weisz Supporting Confidentiality Claim for Submission of
Marin Clean Energy Advice Letter 76-E - Confidential

In accordance with General Order ("G.O.") 66-D, Decision ("D.") 06-06-066, D.08-04-023, D.20-07-005, and D.21-11-029 (collectively, the "Confidentiality Decisions") for the submission of confidential information to the California Public Utilities Commission ("Commission") in an Advice Letter ("AL"), Marin Clean Energy ("MCE") submits the following declaration in support of its claim of confidentiality for the below-specified information provided in MCE AL 76-E.

The undersigned declares, under penalty of perjury, as follows:

1. In my capacity as the Chief Executive Officer, I have knowledge of the information provided in this declaration and am authorized to make this declaration on MCE's behalf.
2. In this AL submission, MCE is securely and confidentially uploading the following documents to the Energy Division through the Commission's File Transfer Protocol ("FTP") system:
   a. "MCE AL 76-E – Confidential"
   b. "MCE Confidentiality Declaration"
3. In this AL submission, MCE is publicly submitting the following documents to the Energy Division and the consolidated service list for Rulemaking 14-07-002 and Application 16-07-015 via email:
   a. "MCE AL 76-E – Public"
   b. "MCE Confidentiality Declaration"
4. Through this declaration, MCE requests that the redacted portions of the following documents be treated as confidential and kept under seal:
   a. Confidential Attachment A – Amendment No. 3 to the Renewable PPA between MCE and CES Electron Farm One, LLC, dated as of May 3, 2024 ("Conflitti PPA 1")
   b. Confidential Attachment B – Amendment No. 3 to the Renewable PPA between MCE and CES Electron Farm One, LLC, dated as of May 3, 2024 ("Conflitti PPA 2")
   c. Confidential Attachment C – 2022 DAC-GT and CSGT RFO Bid Information

d. Confidential Attachment D – 2024 MCE Open Season - Small Scale Stand-Alone Solar Offers
e. Confidential Attachment E 2023-2024 MCE Comparable Amendments

5. This request for confidentiality is being made pursuant to the requirements and authority of the Confidentiality Decisions, Commission G.O. 66-D, California Civil Code 3426.1(d), California Evidence Code 1060, and California Government Code Sections 6254(k) and 7920.000 *et seq*.
6. The attached "Table of Confidential Information" identifies the specific information that is subject to this confidentiality request, provides specific citations to the authority upon which each request is based, provides a granular justification for confidential treatment, and specifies the length of time that the information is to be kept confidential.
7. MCE is complying with the limitations on confidentiality specified in the D.06-06-066 Matrix (as amended by subsequent decisions) for the types of data being submitted subject to a request for confidentiality.
8. To the best of my knowledge, the information being submitted subject to this request for confidentiality is not already public.
9. As set forth in the "Table of Confidential Information", Confidential Attachments A, B, and C contain confidential and highly market-sensitive supporting documentation for MCE AL 76-E.
10. The redacted portions of Confidential Attachments A, B, C, D & E cannot be aggregated, redacted, summarized, masked, or otherwise protected in a way that allows partial disclosure.
11. The following person is designated as the person for the Commission to contact regarding potential release of this information by the Commission:

Dawn Weisz
Chief Executive Officer
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, California 94901
dweisz@mcecleanenergy.org

Executed on May 20, 2024 at San Rafael, California

/s/ Dawn Weisz

Dawn Weisz
Chief Executive Officer
Marin Clean Energy

TABLE OF CONFIDENTIAL INFORMATION
MCE Advice Letter 76-E

Redaction Reference	Authority For Confidentiality Request	Justification for Confidential Treatment	Length of Time Data To Be Kept Confidential
Confidential Attachment A – Amendment No. 3 to Renewable PPA between MCE and CES Electron Farm One, LLC, dated as of May 3, 2024 ("Conflitti PPA 1") Confidential Attachment B – Amendment No. 3 to Renewable PPA between MCE and CES Electron Farm One, LLC, dated as of May 3, 2024 ("Conflitti PPA 2") Confidential Attachment C – 2022 DAC-GT and CSGT RFO Bid Information Confidential Attachment D – 2024 Open Season - Small Scale Stand-Alone Solar Offers Confidential Attachment E – 2023-2024 MCE Comparable Amendments	ESP/CCA Matrix, Item IV(C) as adopted in D.06-06-066 and as modified in D.08-04-023 and D.20-07-005 Commission General Order 66-D Public Utilities Code Section 583 California Civil Code 3426.1(d) California Government Code Sections 7920.000 *et seq.* & 6254(k). California Evidence Code Section 1060	Item IV(C) of the ESP/CCA Matrix provides that contract summaries information is public, including counterparty, resource type, location, capacity, expected deliveries, place of delivery, length of contract, and online date. All other terms qualify for confidential treatment. Confidential Attachments A & B contain information regarding contract price, milestone dates, expected generation, and financial terms. This information is not listed as public in the matrix category, and therefore qualifies for confidentiality as "other terms." Additionally, Confidential Attachments A, B, C, D & E contain market-sensitive and/or trade secret information. Moreover, 3rd party responses to MCE's solicitations may contain information that MCE is not at liberty to disclosure publicly and that may be claimed as privileged, confidential, and/or proprietary. Even if no other authority applied to protect this information, the Commission must protect this information because the public interest in protecting the information clearly outweighs the public interest in disclosure. Disclosures of certain contract terms and underlying information, including but not limited to financial terms and the bidding information and negotiations that lead to the formation and adoption of such contract provisions and information, could provide valuable market-sensitive information to market participants, erode MCE's current or future contract negotiations, and create distortions in the resource adequacy and energy markets. All of the foregoing would	Under ESP/CCA Matrix, Item IV(C) terms are confidential for three years from the date the contract states deliveries to begin, or until one year following expiration, whichever comes first.

		negatively impact MCE and its customers and cause harm to the public. In contrast, the public interest is minimal in public disclosure of pricing and procurement data for a single load serving entity.	

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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 ADMINISTRATIVE LAW JUDGE'S RULING ON TRACK B WORKING GROUP 1 PROPOSALS AND ISSUE 5

Evelyn Kahl,
General Counsel and Director of Policy
Leanne Bober,
Senior Counsel
Eric Little,
Director of Regulatory Affairs

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

May 22, 2024

TABLE OF CONTENTS

SUMMARY OF RECOMMENDATIONS

California Community Choice Association provides the following recommendations in response to the Administrative Law Judge's Ruling on Track B Working Group 1 Proposals and Issue 5:

- Any updates to the marginal generation capacity costs (MGCC) and marginal distribution capacity cost (MDCC) values should provide the same level of intervenor participation as existing mechanisms to ensure transparency;
- Investor-owned utilities (IOU) updating the MGCC to implement community choice aggregator updates to the MGCC in real-time pricing (RTP) billing systems should simultaneously preserve indifference to the extent community choice aggregators must rely on IOUs for implementing RTP rates;
- All customers, rather than exclusively low-income customers, should be included in the scope of customer studies on RTP rates; and
- Load Management Standards cost recovery on behalf of bundled and unbundled customers should be through IOU distribution rates if cost recovery is not available through non-ratepayer or California Energy Commission funds.

**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 ADMINISTRATIVE LAW JUDGE'S RULING ON TRACK B WORKING GROUP 1 PROPOSALS AND ISSUE 5

California Community Choice Association[1] (CalCCA) submits these comments pursuant to the *Administrative Law Judge's Ruling on Track B Working Group 1 Proposals and Issue 5*[2] (Ruling), dated April 24, 2024. The Ruling directs Pacific Gas and Electric Company (PG&E) Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, the IOUs), and invites other parties to comment on the questions in Attachment A to the Ruling.

I. INTRODUCTION

The comments below respond to Ruling questions related to several topics under consideration in Track B. First, CalCCA provides feedback on the California Public Utilities Commission's consideration of updates to marginal generation capacity costs (MGCC) and

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

[2] *Administrative Law Judge's Ruling on Track B Working Group 1 Proposals and Issue 5*, Rulemaking (R.) 22-07-005 (Apr. 24, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M530/K282/530282375.PDF.

marginal distribution capacity costs (MDCC). Specifically, needs for transparency and administrative efficiency must be balanced when contemplating changing the venue for review of ratesetting elements like the MGCC/MDCC. Second, feedback is provided on the scope and funding of low-income customer studies, including the need to address broader questions on RTP rates in addition to the impact on low-income residential customers. Third, CalCCA proposes cost recovery alternatives related to implementation of the California Energy Commission's (CEC) Load Management Standards (LMS).[3]

As set forth in detail below, CalCCA recommends following:

- Any updates to the MGCC and MDCC values should provide the same level of intervenor participation as existing mechanisms to ensure transparency;
- IOUs updating the MGCC to implement community choice aggregator (CCA) updates to the MGCC in real-time pricing (RTP) billing systems should simultaneously preserve indifference to the extent CCAs must rely on investor-owned utilities (IOU) for implementing RTP rates;
- All customers, rather than exclusively low-income customers, should be included in the scope of customer studies on RTP rates; and
- LMS cost recovery on behalf of bundled and unbundled customers should be through IOU distribution rates if cost recovery is not available through non-ratepayer or CEC funds.

II. UPDATES TO MGCC AND MDCC VALUES SHOULD INCLUDE THE SAME LEVEL OF INTERVENOR PARTICIPATION AS EXISTING MECHANISMS TO ENSURE TRANSPARENCY

Updates to MGCC/MDCC should include the same level of intervenor participation as existing mechanisms for updating these values. As PG&E's Advice Letter 7243-E points out, IOUs update MGCC/MDCC values in Phase 2 General Rate Cases (GRC),[4] which occur every four years. These values plug into formulas for determining dynamic prices and can have

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[3] 20 CCR §§ 1621-1625.

[4] *See Pacific Gas and Electric Company Advice 7243-E* (Apr. 19, 2024), at 1 (providing citation to Decision (D.) 21-11-016 establishing requirements to provide marginal cost estimates in Phase 2 of the GRC): https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7243-E.pdf.

nontrivial impacts on the prices to which customers on RTP rates respond through load shifting.[5] The Ruling contemplates whether annual updates to marginal capacity costs are better suited to give customers on RTP rates more accurate and compelling price signals and in what format IOUs should request approval.

Regardless of the format the Commission chooses, the Commission should prioritize transparency and administrative efficiency. For example, three existing processes exist that can provide a better opportunity for party intervention than advice letters while not developing an entirely new process. *First*, the Commission can modify the GRC process to allow for a special track that reviews annual updates to the MGCC/MDCC for RTP rates. *Second*, the Commission can integrate review of MGCC/MDCC values into the annual Energy Resource Recovery Account Forecast process. *Third*, the Commission can utilize the IOU Rate Design Window as a means for reviewing updates to marginal capacity cost values. The Commission should consider these alternatives in the context of the uncertainty regarding the ultimate scope of adoption of RTP rates. In any event, modifications to elements of RTP rates like MGCC and MDCC should not differ from other aspects of ratesetting which currently have opportunities for significant party analysis and intervention. Overall, the highest priorities for such processes should remain transparency and efficiency.

III. TO THE EXTENT CCAS MUST RELY ON IOUS FOR IMPLEMENTING RTP RATES, IOU UPDATES TO THE MGCC MUST ALSO IMPLEMENT CCA UPDATES TO THE MGCC IN RTP BILLING SYSTEMS TO PRESERVE INDIFFERENCE

For the duration of the expanded RTP pilots authorized in this proceeding, the Commission should require IOUs to implement CCA updates to MGCC values at the same time

5 *See id.,* at 2 (summarizing impact of increased marginal costs on real-time price signals for customers on dynamic rates).

as IOUs' updates to preserve customer indifference. The expanded RTP pilots will be administered and implemented by the IOUs, requiring the CCAs to rely on IOUs to provide participating CCA customers any price signals based on CCA dynamic rates. IOUs have worked with CCAs to integrate CCA values into formulas that generate dynamic prices. One of these values is the MGCC. Regardless of the format the Commission adopts for updating MGCC values, the IOUs should work with CCAs to provide the opportunity to recalculate CCA MGCC values before the IOUs push their own updates into RTP billing systems. Otherwise, bundled and unbundled customers will be exposed to RTP prices with different levels of accuracy solely because the CCAs do not have direct control over IOU billing systems. For this reason, to the extent CCAs must rely on IOUs to implement RTP rates, the Commission should require IOUs to implement MGCC updates for IOUs and CCAs in RTP billing systems at the same time.

IV. THE SCOPE OF CUSTOMER STUDIES FOR RTP RATES SHOULD INCLUDE UNDERSTANDING BENEFITS TO ALL CUSTOMERS, INCLUDING LOW INCOME CUSTOMERS, IN ADDITION TO BENEFITS TO THE GRID

The Ruling asks whether the Commission should direct IOUs to study the needs of residential, low-income customers with respect to responding to RTP rates.[6] Any customer studies for RTP rates should not be limited to only low-income customers – all customers will pay for such customer studies and much is still needed to be learned about how all customer classes may respond to RTP rates versus simpler time-varying rates like time-of-use rates. Therefore, in addition to low-income customers, the Commission should require customer studies to include data from all customers, as well as studying overall RTP benefits to the grid.[7]

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6 *See* Ruling, Attachment A, at 6 (questions for party comment 9 – 11).

7 In addition, any study (especially those funded through IOU distribution rates) should incorporate data on both bundled and unbundled customers to ensure a robust data set.

Appendix A contains a list of questions the Commission should scope into studies related to RTP rates and residential customers.

V. LMS COST RECOVERY ON BEHALF OF BUNDLED AND UNBUNDLED CUSTOMERS SHOULD BE THROUGH IOU DISTRIBUTION RATES IF COST RECOVERY IS NOT AVAILABLE THROUGH NON-RATEPAYER OR CEC FUNDS

Ruling Questions 12 and 13 direct the IOUs to respond to questions on cost recovery authorization and processes for LMS requirements. The LMS requirements apply to the IOUs, to Large CCAs, and to Large Publicly Owned Utilities (POU), with some of the "tools and services" necessary to implement the LMS required to be jointly created by these load-serving entities (LSE). While the Market Informed Demand Automation Server (MIDAS) has been funded by the CEC, all parties have advocated for improvements needed to ensure its efficacy. The LMS also requires the LSEs to jointly develop a Single Statewide Tool (SST) to allow customers to access their dynamic rates under the LMS, either directly or through third party automated service providers (ASP). While non-ratepayer or CEC agency funding is the preferred method for all LMS requirements (including MIDAS upgrades and the SST), to the extent such funding is not available CalCCA recommends that the Commission order cost recovery through IOU distribution rates on behalf of bundled and unbundled customers to prevent cost-shifts.

As an initial matter, it is reasonable that tools and services created for the benefit of all California customers/residents and third parties be funded through non-ratepayer funds. The majority of customers will have access (either directly or through third-parties such as ASPs authorized on their behalf) to and the ability to benefit from the LMS statewide tools. Even for those customers not directly utilizing the LMS tool and services, if the LMS is successful it should result in grid benefits that benefit all Californians. Therefore, funding through non-ratepayer funds is appropriate.

Second, if non-ratepayer funds are not generally available, the CEC should explore accessing funds to develop and maintain the tools and services necessary to implement the LMS. For instance, MIDAS was developed and funded by the CEC, but needs improvements and upgrades if it is to serve as a repository for hourly rates and eventually interact with the Commission's price machine or the SST. CEC staff, however, have communicated to parties informally that there is currently no internal funding available to make such improvements. Further, parties are currently struggling to identify plausible ways for over 20 LSEs to jointly fund the SST. CalCCA is not aware of any precedent for IOUs, CCAs, and POUs to jointly fund, develop, and maintain such a tool. To the extent possible, the CEC should access funds to complete the MIDAS improvements, and to fund the SST, as both will presumably benefit all Californians.

If non-ratepayer funds and/or CEC funding are not available however, the Commission should order equitable recovery of costs of the tools and services, as well as other categories of administrative and technology costs, between bundled and unbundled customers. Furthermore, in the event CEC or other non-ratepayer funds <u>are</u> made available for either the SST or MIDAS, there will likely still be categories of administrative and technology costs that need to be recovered equitably between bundled and unbundled customers. In either event, the Commission should order the recovery of IOU and CCA costs on behalf of all customers (bundled and unbundled) on a load share basis through IOU distribution rates (Large POUs will separately recover their own load share of the costs). Individual CCA costs, such as for administrative and/or technology costs, can be proposed through annual budget Advice Letters. Once approved, such costs can be included in the IOUs' budget forecasts.

For the SST, once it is established, a mechanism/structure should be created for third parties (such as ASPs) to pay to utilize the SST. The CEC can then allocate revenues from such third-party use back to the IOUs for all bundled and unbundled customers (on behalf of themselves and the CCAs) and Large POUs.

In any event if non-ratepayer or CEC funding is not available, the Commission must prevent cost shifts between bundled and unbundled customers, preferably by ordering cost recovery on behalf of IOUs and CCAs through distribution rates. If the Commission does not allow CCA cost recovery through distribution rates, any IOU costs must be recovered through generation rates to prevent cost shifts from bundled to unbundled customers (who would otherwise be paying such costs twice through distribution rates and the CCA generation rates).

VI. CALCCA RESPONSES TO ATTACHMENT A OF THE RULING

1.2 MGCC Questions for Party Comments:

Should the CPUC require annual updates to the MGCC for hourly marginal cost based rates for all large IOUs? Why or why not?

See Section II., above.

If so, what methodology should the CPUC authorize for the annual updates? For example, should the same approach as proposed by PG&E in AL 7243-E be used?

See Section II., above.

1. **How would an annual adjustment of the MGCC for hourly marginal cost-based rates align with the CPUC's updated Rate Design Principles and new Demand Flexibility Design Principles? For example, would an annual update encourage customer behaviors that improve electric system reliability in an economically efficient manner?**

See Section II., above.

2. **If the Commission adopts annual updates, what process should facilitate an annual adjustment of the MGCC for hourly marginal cost-based rates? For example, should the IOUs be required to file an**

Advice Letter to update the MGCC for hourly marginal cost-based rates? Should this process be incorporated into the IOUs' annual consolidated filings or another process?

See Section II., above.

2.4 MDCC Questions for Party Comments:

3. **Should the CPUC require annual updates to the revenue recovery target for the MDCC for hourly marginal cost-based rates in order to improve the accuracy and effectiveness of the distribution price signal and reflect cost-causation for all IOUs?**

See Section II., above.

a. **If the CPUC authorizes annual updates, what methodology should the CPUC authorize for the annual updates? For example, should the CPUC require that the same approach as proposed by PG&E in AL 7243-E be used?**

See Section II., above.

b. **Would an annual adjustment of the revenue recovery target for the MDCC be aligned with the CPUC's updated Rate Design Principles and new Demand Flexibility Design Principles?**

CalCCA has no comment at this time.

4. **If the Commission requires annual updates to the MDCC for hourly marginal cost based rates, what process should facilitate the annual updates? For example, should the IOUs be required to file an annual Advice Letter? Should this process be incorporated into the IOUs' annual consolidated filings or another process?**

See Section II., above.

5. **Should the CPUC require using multipliers (either EPMC or another similar scalar) to the MDCC for hourly marginal cost-based rates? Would it be reasonable for this multiplier to apply to both imports and exports?**

CalCCA has no comment at this time.

6. ***(For the IOUs only) What is the cost, scope and timeline for each IOU to implement a CEC-LMS complaint hourly marginal cost-based with the following geographic granularity for the hourly distribution prices:***

a. An approach similar to what is being implemented in PG&E's upcoming VGI pilot, where the hourly distribution prices will be based on grouping circuits of similar load profiles into clusters.

CalCCA has no comment at this time.

b. An approach where the hourly distribution prices are based on the local substation load for all circuits downstream of each substation.

CalCCA has no comment at this time.

3. Compliance with CEC LMS Deadlines for Marginal Cost Hourly Rates

7. When and in what procedural venue does each IOU propose to submit its application for marginal cost-based rates? (Each IOU should provide a separate response to this question.)

CalCCA has no comment at this time.

4. Study for Low Income Customers

8. Should the Commission direct the IOUs to conduct a new study or modify a planned study to better understand:

a. The needs of low-income residential customers with respect to responding to dynamic rates and whether and how residents of disadvantaged communities can benefit from dynamic rates in certain climate zones (e.g. by providing inexpensive tools for automating air conditioning), and

See Section IV., above and scope questions in Appendix A.

b. How low-income residential customers would respond to dynamic rates and/or more cost-reflective TOU rates?

See Section IV., above and scope questions in Appendix A.

9. Will current or upcoming studies conducted on low-income customers or customers in disadvantaged communities (e.g., Community Based Organizations Arrearages Case Management Pilot study authorized in D.24-02-046 in the residential energy disconnections proceeding, Rulemaking 18-07-005) make it unnecessary to direct a new study in this proceeding?

CalCCA has no comment at this time.

10. If the CPUC decides to direct the IOUs to conduct a new study:

a. What should be the scope of that study?

See Appendix A attached hereto for list of questions to include in scope.

b. Should the Commission direct an IOU to conduct an RFP for an independent consultant to conduct the study? If so, what should be the criteria for selecting the consultant?

CalCCA has no comment at this time.

c. How should stakeholders be involved in developing the study?

CalCCA has no comment at this time.

d. When should the study be completed?

Studies should complete before CEC LMS deadlines require implementation of RTP rates in 2027 so that both IOUs and CCAs can integrate any findings into their RTP rate offerings.

e. What process should be used to recover the costs of the study?

See Section IV., above.

f. Should a budget be authorized for the study, and if so, what budget should be authorized?

CalCCA has no comment on budget size at this time.

5. Implementation of CEC LMS Requirements

11. What implementation costs need to be authorized by the Commission before the end of 2024 in order to comply with the CEC LMS requirements?

See Section V., above.

12. Please propose the process details regarding the revenue/cost tracking account for these implementation costs (i.e., memorandum account or balancing account). Please also address whether a new or an existing account should be used for these costs.

CalCCA has no comment at this time.

VII. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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

May 22, 2024

APPENDIX A
TO
CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE ADMINISTRATIVE LAW JUDGE'S RULING ON TRACK B WORKING GROUP 1 PROPOSALS AND ISSUE 5

Questions to Guide Commission Customer Studies on Real Time Pricing Rates Including, but Not Limited to:

1. How can low-income and Disadvantaged Communities' customers achieve private energy and non-energy benefits on real time pricing (RTP) rates?

2. Is there a level of electrification technology adoption (e.g., automation) necessary to achieve private energy benefits for low-income customers?

3. Do low-income customers lack access to the technology (smart devices, internet, etc.) necessary to benefit from RTP rates?

4. Are there gaps in access to that technology between low-income customers and higher-income customers?

5. Do RTP rates have effects that reduce rates for all customers, not just those on RTP rates?

6. What is a realistic level of customer participation in RTP rates to expect?

7. What is a realistic level of residential load shifting to expect from RTP rates?

8. Do low-income customers experience lower levels of load elasticity than higher income customers?

9. What impact would increased price volatility from RTP rates have on low-income customer affordability (e.g., bill size month to month)?

10. What consumer protections could be considered to reduce low-income customer affordability risk under RTP rates?

11. How does RTP affect investments of customers who have participated in energy efficiency programs?

CALCCA
ADVANCING LOCAL ENERGY CHOICE

May 22, 2024

By Email: Juan E. Buitrago (jbuitrago@caiso.com)

Ms. Jan Schori
Chair
California ISO Board of Governors

Re: Interconnection Process Enhancements

Dear Chair Schori and Members of the Board,

The California Community Choice Association (CalCCA) respectfully submits this letter to the California Independent System Operator (CAISO) Board of Governors regarding CAISO management's Interconnection Process Enhancements (IPE) proposal, which will be discussed at the May 23, 2024, meeting and decided upon at the June 12, 2024, meeting. CalCCA asks that the CAISO Board of Governors direct management to adopt the IPE proposal.

CalCCA is a trade association representing the interests of 24 community choice aggregators (CCA) in California. CalCCA's membership serves over 14 million customers in over 200 cities and counties throughout the state, representing roughly one-third of the CAISO load in California. As load-serving entities (LSE) actively procure new electric generating resources to serve California customers, California CCAs have a direct interest in ensuring an efficient and effective interconnection process that supports the accelerated pace of clean energy resource development.

The IPE proposal advances much-needed transformations to the interconnection cluster study and queue management processes while maintaining open access to the transmission system. The proposal intends to prioritize interconnection requests by ranking requests within available transmission zones based on indicators of readiness; commercial interests, project viability, and system needs. It also recognizes the importance LSE interest will play when narrowing down the pool of interconnection study requests.

LSEs, as procuring entities, conduct long-term planning activities in their individual integrated resource plans, where they start to identify the technologies, locations, and magnitudes of projects they will pursue to support the communities they serve. LSEs must procure a range of technologies to meet reliability and green-house gas-reduction targets in a cost-effective manner that meets their customers' needs and, for some LSEs like CCAs, directives from their boards. This information is factored into the California Public Utilities Commission's (CPUC) preferred system plan, which then informs the CAISO's transmission planning process. Without an LSE interest scoring criterion, the CAISO would risk having an interconnection queue that is not aligned with resource and transmission planning processes taking place in these forums. Given that reliability depends critically on having the right mix of resources on the grid, this alignment with planning is fundamentally important to CAISO's operations.

California Community Choice Association
1121 L Street, Suite 400, Sacramento, CA 95814
info@cal-cca.org | cal-cca.org

CCAs are committed to making the LSE point allocation process as transparent and fair as possible. The CAISO can play an important role in this by providing LSEs with a complete dataset on interconnection requests including technology type, interconnection point, capacity, and developer as early as possible to make sure no project inadvertently "falls through the cracks" and to provide a complete picture for LSEs' prioritization of different interconnection requests vs. the pool of options. Given the in-depth considerations LSEs will put into their scoring, CalCCA urges the CAISO to provide LSEs with at least a month between when the application window closes and the scoring allocations are due, to ensure LSEs have enough time to allocate their points thoroughly and effectively. CalCCA supports the CAISO's objective of a robust, fair, and transparent point allocation process, and sufficient information availability and scoring time will support this objective.

CalCCA appreciates the direction provided by the CAISO in its addendum to the Final Proposal on best practices to incorporate into the LSE point allocation processes. CCAs are open to continuing to work with the CAISO and developers to improve the LSE point allocation process as LSEs, the CAISO, and developers gain experience with the new interconnection study process.

Given these considerations, CalCCA respectfully asks that the CAISO Board of Governors direct management to adopt the IPE proposal.

Respectfully,

Eric Little
Director of Regulatory Affairs
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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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 COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON NEED AND PROCESS FOR CENTRALIZED PROCUREMENT OF SPECIFIED LONG LEAD-TIME RESOURCES

Evelyn Kahl,
General Counsel and Director of Policy
Lauren Carr,
Senior Market Policy Analyst
Eric Little,
Director of Regulatory Affairs

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

May 24, 2024

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SUMMARY OF RECOMMENDATIONS

- The Commission must adhere to Public Utilities Code sections 454.51 and 454.52 when establishing the central procurement process and making central procurement decisions, including the right of self-procurement by community choice aggregators (CCAs).

- <u>Eligible Resources</u>: The Commission should use central procurement sparingly since many of the resources described are either being procured by load-serving entities (LSE) or do not have a lead time greater than five years. If the Commission pursues any central procurement, it must focus on emerging technologies and prioritize affordability.

- <u>Cost-Benefit Analysis</u>: The Commission must use the most up-to-date information from LSEs on their procurement activity and account for planned procurement that would result in LSEs contracting at a later time and still bringing those resources to commercial operation in time to meet their needs. Such analysis is likely to demonstrate that the only opportunity for central procurement is for a small amount of offshore wind.

- <u>Integration</u>: The Commission must carefully proceed with central procurement decisions to avoid central procurement simply serving as competition to LSE procurement. This is particularly important given the upcoming Reliable and Clean Power Procurement Program.

- <u>Cost and Benefit Allocation</u>: The Commission must ensure that its allocations do not disincentivize LSEs from procuring independently and do not penalize early actors. Benefits (e.g., Resource Adequacy, Renewable Portfolio Standard, green-house gas-free) should be allocated consistent with the allocation of costs.

- <u>Timeline</u>: The Commission must be as transparent as possible so that LSEs have a clear understanding of the central procurement process and its costs. This process should occur within the defined Integrated Resource Plan (IRP) process so that it is fully informed by the most recent activities in the IRP which plan for LSE-based procurement and also allow for CCA self-procurement of the CCA share of any identified need. The Commission should also make clear that any need determination made by September 1, 2024, will not necessarily result in any procurement authorization. Rather, if the Commission determines a need, it should direct the Department of Water Resources (DWR) to solicit offers for resources. The Commission should then review the viability and pricing of offers against net-benefit scenarios to determine if the DWR should proceed with procurement.

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 COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON NEED AND PROCESS FOR CENTRALIZED PROCUREMENT OF SPECIFIED LONG LEAD-TIME RESOURCES

California Community Choice Association[1] (CalCCA) submits these comments pursuant to *Administrative Law Judge's Ruling Seeking Comments on Need and Process for Centralized Procurement of Specified Long Lead-Time Resources*[2] (Ruling), dated April 26, 2024, and *Analysis for Centralized Procurement of Specified Long Lead-Time Resources*, dated April 2024.[3] The Ruling seeks feedback from parties on options for initial use of the centralized procurement mechanism created in Assembly Bill (AB) 1373 (Stats. 2023, Ch. 367), where the California Public Utilities Commission (Commission) may request that the California Department of Water Resources (DWR) procure electricity from certain types of resources, as a

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

2 *Administrative Law Judge's Ruling Seeking Comments on Need and Process for Centralized Procurement of Specified Long Lead-Time Resources*, R.20-05-003 (Apr. 26, 2024): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M530/K323/530323853.PDF.

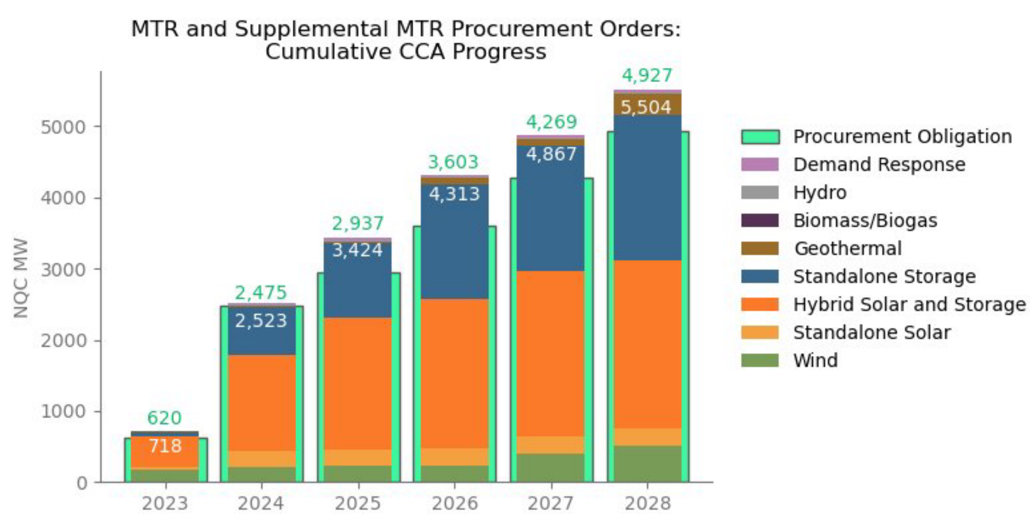
3 *Analysis for Centralized Procurement of Specified Long Lead-Time Resources* (Apr. 2024): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/ab1373/need-determination-analysis-centralized-procurement-of-specified-llt-resources.pdf.

central procurement entity (CPE) on behalf of customers of all load-serving entities (LSE) under the Commission's Integrated Resource Plan (IRP) purview.

I. INTRODUCTION

The development of diverse electric generation in untapped, resource-rich areas is critical to achieving the state's Senate Bill (SB) 100 (De León, Chapter 312, Stats. of 2018) climate goals and maintaining system reliability. LSEs are making progress on this critical need by procuring a diverse set of resources, including long-lead time (LLT) resources, in response to Commission procurement orders and planning for additional procurement in their IRPs. Community choice aggregators (CCA), for example, have met their first mid-term reliability (MTR) procurement targets in aggregate and are on track to meet future targets, as demonstrated in Figure 1. Furthermore, LSE diversity means that CCAs' elected boards have in many cases chosen more aggressive targets than the Commission, driving procurement above IRP targets. Since CCAs have a track record of being effective partners in achieving state goals, preserving that value should be a top consideration in designing the CPE.

Figure 1: Aggregate CCA Progress on IRP Procurement Orders
(Source: CalCCA Member Data Request)



AB 1373 authorizes another vehicle for the procurement of new resources: centralized procurement via DWR. AB 1373 requires the Commission to evaluate the need for centralized procurement by September 1, 2024, and request that DWR conduct central procurement of certain eligible LLT resources until January 1, 2035. The Ruling puts forth a series of questions aimed at informing the Commission's September 1, 2024, need determination. Several questions and narratives throughout the Ruling reflect inconsistencies with the statute that the Commission must remedy prior to making its initial need determination. Central procurement processes and decisions must fully adhere to the statute established in section 454.51.[4]

Of the resources identified in the Ruling as potential candidates for central procurement, offshore wind (OSW) appears to have the most potential for some level of central procurement if a need is identified. This is because of the significant investments in transmission and port infrastructure required, the relative newness of the technology, the potential for spurring economies of scale, and the fact that LSEs have not yet begun to contract with OSW.

As the Commission considers the possibility of centrally procuring OSW, it should exercise caution to protect customer costs by focusing on procurement that has demonstrated net benefits. Given the challenges with procuring OSW identified in the ruling, the Commission should consider the likelihood of DWR's ability to successfully procure OSW now rather than some time in the near future.[5] It should also recognize that LSEs are interested in a pathway to eventually procuring OSW themselves, as represented in California Community Power's (CC Power) Memorandum of Understanding (MOU) with CADEMO,[6] and minimize interference with LSE procurement efforts.

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4 All subsequent code sections cited herein are references to the California Public Utilities Code (Cal. Pub. Util. Code) unless otherwise specified.

5 Ruling, at 8: "There may be many reasons why LSEs have not yet procured OSW projects, including insufficient port development, lack of turbine fabrication infrastructure, lack of installed offshore transmission infrastructure, or under-developed interconnection and permitting processes to accommodate OSW projects. These reasons may be compounded by the nascent global deployment of floating OSW technology, which may have culminated in developer bids that LSEs deemed to be unfavorable to their ratepayers."

6 *California Community Power and CADEMO Execute Offshore Wind MOU*: https://cal-cca.org/california-community-power-and-cademo-execute-offshore-wind-mou/.

If the Commission identifies a need for central procurement by September 1, 2024, central procurement should not reach beyond OSW to the other types of technologies identified in the Ruling - out-of-state (OOS) wind, geothermal, and long-duration energy storage (LDES). These technologies generally do not meet AB 1373's eligibility criterion of having a construction and development lead time of at least five years. In addition, LSEs – particularly CCAs – are in the process of meeting the 18,800 megawatt (MW) procurement requirements ordered by the Commission over the last several years.[7] Their efforts are hampered not by the ability to contract for such technologies, but by project delays arising from interconnection, supply chain, and permitting delays. Similarly, the lack of contracting with OSW is not because LSEs lack interest, but rather, because the OSW developers do not yet have complete information about their costs. These procurement challenges are present regardless of the procuring entity – a CPE or LSEs, suggesting that a CPE may not solve the issues California's LSEs are facing.

Ongoing and future procurement obligations for new resources with demonstrated commercial viability must remain with LSEs. Introducing a CPE for technologies that LSEs are already in the process of procuring could impair LSEs' efforts and delay new resources. This is particularly true if the uncertainty leads to reduced participation by developers in LSEs' resource solicitations or exacerbates sources of delay LSEs are already experiencing. It could also increase customer costs by adding excess demand into a market with limited sources of supply. Central procurement, thus, must be limited to circumstances that (1) require a long lead time, (2) accelerate required transmission or regional infrastructure needed to spur the development of emerging technologies, and (3) avoid interference with ongoing LSE procurement.

[7] See footnote 4, supra.

With these considerations in mind, CalCCA offers the following recommendations through its responses to the questions in the Ruling:

- The Commission must adhere to sections 454.51 and 454.52 when establishing the central procurement process and making central procurement decisions, including the right of self-procurement by CCAs.

- Eligible Resources: The Commission should use central procurement sparingly since many of the resources described are either being procured by LSEs or do not have a lead time greater than five years. If the Commission pursues any central procurement, it must focus on emerging technologies and prioritize affordability.

- Cost-Benefit Analysis: The Commission must use the most up-to-date information from LSEs on their procurement activity and account for planned procurement that would result in LSEs contracting at a later time and still bringing those resources to commercial operation in time to meet their needs. Such analysis is likely to demonstrate that the only opportunity for central procurement is for a small amount of OSW.

- Integration: The Commission must carefully proceed with central procurement decisions to avoid central procurement simply serving as competition to LSE procurement. This is particularly important given the upcoming Reliable and Clean Power Procurement Program (RCPPP).

- Cost and Benefit Allocation: The Commission must ensure that its allocations do not disincentivize LSEs from procuring independently and do not penalize early actors. Benefits (e.g., resource adequacy, Renewable Portfolio Standard (RPS), green-house gas (GHG) -free) should be allocated consistent with the allocation of costs.

- Timeline: The Commission must be as transparent as possible so that LSEs have a clear understanding of the central procurement process and its costs. This process should occur within the defined IRP process so that it is fully informed by the most recent activities in IRP which plan for LSE-based procurement and also allow for CCA self-procurement of the CCA share of any identified need. The Commission should also make clear that any need determination made by September 1, 2024, will not necessarily result in any procurement authorization. Rather, if the Commission determines a need, it should direct DWR to solicit offers for resources. The Commission should then review the viability and pricing of offers against net-benefit scenarios to determine if DWR should proceed with procurement.

Adoption of these recommendations will ensure the development of a diverse resource portfolio, promote customer affordability, and preserve LSEs' ability to procure for their customers.

II. THE COMMISSION MUST ADHERE TO PUB. UTIL. CODE SECTIONS 454.51 AND 454.52 WHEN ESTABLISHING THE CENTRAL PROCUREMENT PROCESS AND MAKING CENTRAL PROCUREMENT DECISIONS, INCLUDING THE RIGHT OF SELF-PROCUREMENT BY CCAS

Several instances in the Ruling depart from or overlook section 454.51, which outlines the provision for 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 in a cost-effective manner."[8] Section 454.51(d) states that the Commission shall:

> Permit community choice aggregators to submit proposals for satisfying their portion of the renewable integration and diverse resources need identified in subdivision (a). If the commission finds this need is best met through long-term procurement commitments for resources, community choice aggregators shall also be required to make long-term commitments for resources. The commission shall approve proposals pursuant to this subdivision if it finds all of the following:
>
> (1) The resources proposed by a community choice aggregator will provide equivalent integration of renewable energy.
>
> (2) The resources proposed by a community choice aggregator will promote the efficient achievement of state energy policy objectives, including reductions in greenhouse gas emissions.
>
> (3) Bundled customers of an electrical corporation will be indifferent from the approval of the community choice aggregator proposals.[9]

The Ruling, however, diverges from section 454.51(d) in three key areas. First, when discussing the Commission's authority for IOU-based central procurement, it states:

> Nothing would prohibit the Commission from assigning one or more IOUs to conduct centralized procurement of LLT resources in addition to, or instead of, the option to utilize the new mechanism of centralized procurement by DWR authorized in AB 1373.[10]

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8 Cal. Pub. Util. Code § 454.51(a).
9 Cal. Pub. Util. Code § 454.51(d).
10 Ruling, at 2.

Neither section 454.51 nor 454.52 provide such authorization in the broad manner characterized by the Ruling. While the Commission indeed may assign central procurement to an IOU, it may not do so before allowing CCAs to self-procure. Section 454.51(d) provides CCAs a right of self-procurement for their portion of the identified need to support "a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner."[11]

Second, the Ruling contemplates central procurement of resources that it has not demonstrated meet AB 1373's requirement that a resource procured by DWR have construction and development timelines of five years or more. For the reasons described in response to Question 1, OOS wind, geothermal, and LDES fall outside this authorization since there is no evidence in the record that these resources take longer than five years to build and construct.

Third, the Ruling overlooks the statute's intent to allow LSEs an opportunity to self-procure prior to DWR contracting based on the Commission's identified need. As described in response to Question 13, section 454.52 states that the Commission is to provide six months between determining that there is a need for the procurement of eligible energy resources and requesting DWR exercise its central procurement function.[12] This mandatory six-month windows' intent is to allow LSEs to procure their fair share of the need. As the Senate Energy and Utilities Committee made clear in their August 31, 2023, analysis:

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11 Cal. Pub. Util. Code § 454.51(a).

12 Cal. Pub. Util. Code § 454.52.

> The intent for the six month window is to allow other LSEs the opportunity to procure their share of their load if they elect to do so. This approach is a long-held principle of CCAs whose primary (if not exclusive) mission is to procure energy on behalf of their load. Such an approach seems appropriate to ensure LSEs exercise their responsibility to procure resources for their load, prior to a state agency stepping in. In this regard, it's possible DWR procurement may not ever be used, or perhaps only used when truly necessary because the resource was too difficult for any individual LSE, or a few LSEs, to procure.[13]

The Commission must remedy these legal errors to ensure its central procurement processes and decisions adhere to the statute.

III. CALCCA RESPONSES TO QUESTIONS IN SECTIONS 2.1, 3.1, 4.1, 5.1, AND 6.1 OF THE RULING

2.1. Eligible Resources

1. Please comment on whether Figure 1 above outlines the appropriate criteria for considering whether a resource should be procured via the DWR centralized procurement mechanism. Are these the right criteria or are there others that should be added or substituted?

a. The Commission Should not use Four of the Five Criteria Identified in Figure 1 to Justify the Need to Procure a Technology through Central Procurement, Especially When Considered Independently

The Ruling identifies five criteria for considering whether DWR should procure a resource as a CPE. It classifies the criteria in Figure 1 as either "procurement challenges" or "market transformations." The procurement challenges identified in the Ruling are either (1) insufficient justification for central procurement, or (2) challenges that shifting the procuring entity—from LSEs to a CPE—will not address. The first procurement challenge is "mismatched size of resource and/or transmission between buyers and sellers." This challenge is not a justification for the use of CPE. There are numerous examples of developers selling large projects that require transmission upgrades to multiple off-takers. For example, the SunZia OOS wind project is moving forward with

[13] AB 1373 Senate Committee on Energy, Utilities and Communications Bill Analysis (Version Aug. 31, 2023, published Sept. 6, 2023), at 14.

construction after securing multiple California LSE off-takers and planning to use the Subscriber Participating Transmission Owner (PTO) model to fund the needed transmission build.[14]

Similarly, there are numerous instances of LSEs jointly procuring large LLT resources. For example, CC Power, a joint powers authority comprised of nine CCAs, contracted for a 50 MW/400-megawatt hour (MWh) LDES project. While the Ruling classifies LDES as a large-scale resource that "may be challenging to finance and build without a single contract,"[15] LSEs have proven that they can contract for large LLT projects without the assistance of a CPE. The first challenge alone is, therefore, not sufficient justification to direct central procurement by DWR.

The second procurement challenge is "cost-effective across a broad range of future scenarios but not being procured in significant volumes." Rather than directing central procurement based on this criterion, the Commission should question why the technology is not being selected despite its cost-effectiveness. The Commission will find that it likely cannot resolve procurement challenges for cost-effective resources simply by shifting the procurement responsibility from the LSEs to DWR. The Commission should consider the sources of the following procurement challenges and seek to resolve those challenges specifically rather than directing central procurement:

- Generation Availability: If a certain technology is not readily offered in LSE request for offers (RFO), adding a CPE will likely exacerbate such availability challenges. Introducing a central procurement opportunity for technologies LSEs are already in the process of procuring or attempting to procure could impair LSEs' efforts if the uncertainty leads to reduced participation by developers in LSEs' resource solicitations. LSEs have already had experiences in the market causing concern that developers may have reduced their participation in RFOs with the anticipation of a new central procurement opportunity. Adding a CPE to the

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14 Howland, Ethan, *Pattern Energy Secures $11b in Financing, Starts Full Construction on Sunzia Wind, Transmission Projects* (Jan. 3, 2024): https://www.utilitydive.com/news/pattern-energy-sunzia-transmission-wind/703508/.

15 *California Community Power Members Approve Second Lithium Ion Long-Duration Energy Storage Contract* (Mar. 7, 2022): https://cacommunitypower.org/cc-power-members-approve-second-long-duration-contract/.

mix would add additional demand to a limited supply pool (e.g., geothermal resources can only be sited in very specific locations dependent on geography). Providing a clear signal that the procurement responsibility lies with the LSE should improve availability for these technology types.

- Transmission and Interconnection: Some projects require large or complex transmission builds or network upgrades to interconnect to the California Independent System Operator (CAISO) Balancing Authority Area (BAA). The LSE and the developer are not in control of such infrastructure build or upgrade timelines, which can often become delayed due to supply chain issues, workforce, shortages, network upgrade delays, or other factors. The Commission should communicate with developers to understand the issues they are facing. The Commission should also work with the CAISO to ensure a close link between resource planning, procurement, transmission planning, and interconnection that ensures coordinated progress on resource development.

- Deliverability Uncertainty: OOS resources require maximum import capability (MIC) allocations to ensure they are deliverable to the CAISO BAA. LSEs cannot receive MIC multiple years in advance of a resource's commercial online date. Deliverability uncertainty may present barriers to procuring OOS resources because LSEs do not have assurances that the resources will be deliverable to California load. The Commission should work with the CAISO to consider ways to resolve this uncertainty rather than introduce another procuring entity.

- Infrastructure needs: There is a significant need for port infrastructure to enable OSW as a resource. Without this infrastructure, regardless of the entity contracting with a developer, completion and deployment of the resource will be difficult if not impossible. The Commission should investigate how it and the state can better encourage port infrastructure development directly rather than indirectly by contracting for OSW.

Each of these procurement challenges can impact contracting regardless of the procuring entity. When this is the case, the Commission should defer to LSEs to procure, given their experiences and successes navigating such challenges thus far and the adverse impacts adding a CPE may have on the market.

The "market transformation" criteria identified in the Ruling are (1) large resource potential, (2) serves a key role in future portfolios without readily available substitutes, and (3) emerging technology with likelihood of cost reductions through learning. The first two market transformation criteria are not relevant for determining if a technology type is a good candidate for central procurement.

The first market transformation criterion, "large resource potential" is not relevant for making central procurement decisions because many technologies have large resource potential but are not good candidates for central procurement because they are not LLT and have proved commercial viability through LSE procurement (e.g., solar, wind, lithium batteries). Other technologies have large resource potential but require significant transmission investment and development to make these resources deliverable (e.g., OOS wind). It is not central procurement that will get technologies with large resource potential built, but rather the development of transmission in zones that will better enable the development of these technologies.

The second market transformation criteria, "serves a key role in future portfolios without readily available substitutes," also does not sufficiently justify a resources' candidacy for central procurement. In particular, the Commission has not demonstrated in the record that one net qualifying capacity (NQC) MW of one technology is not a reasonable substitute for one NQC MW of another. For example, if the Commission finds a need that OSW can satisfy, some combination of other resources could presumably fill the same need if that combination of resources can produce the same output profile as the OSW can. When making central procurement decisions, the Commission must determine whether central procurement has greater net benefits than an alternative combination of resources with an equivalent profile procured by LSEs.

b. The Commission Should Only Approach Central Procurement Decisions with the Goal of Promoting The "Emerging Technology with Likelihood of Cost Reductions Through Learning" Criterion

Of the criteria documented in Figure 1, the Commission should only consider the "emerging technology with likelihood of cost reductions through learning" criterion in making its central procurement decisions. Emerging technologies are typically high-risk projects, and there may be cases where those risks should be borne broadly when investments will result in spurring future development opportunities for LSEs, enhancing development efficiencies, or promoting economies of scale. OSW, for example, would benefit from state and federal coordination to minimize risks and ensure the most cost-effective path forward to deploying the technology, given its unique infrastructure needs.

Centralized procurement of emerging technologies can help bring the resources to maturity. When determining what technologies qualify as emerging technologies, the Commission should not include those that LSEs have proven they can procure on their own so as not to disrupt procurement efforts already in place. The Commission must make careful considerations to ensure it directs the right quantities of central procurement at the right times, balancing the benefits of procuring emerging technologies with the risks and costs of doing so.

c. The Commission Should Adhere to the Eligibility Requirements in the Statute and Add Criteria to Further Narrow Down the Scope of Central Procurement

First and foremost, the Commission should add the criterion, "meets the eligibility criteria mandated in AB 1373." All other criteria, including the emerging technology criterion and the criteria described below, should serve to further focus the Commission's efforts for central procurement to minimize its risks and adverse impacts. AB 1373 lists one of the eligibility criteria as having a construction and development lead time of at least five years. The construction and development lead time must not include the transmission and interconnection time associated with bringing the resource online. Those factors do not contribute to construction and development timelines for the resource and do not signal procurement challenges that the Commission can resolve by shifting the procurement responsibility from the LSE to DWR.

Before including any resource in the scope of a request to DWR, the Commission will need to develop a record of substantial evidence of the timelines of construction and development.

Apart from OSW, the technologies contemplated in the Ruling do not appear to meet this five-year criterion. There are recent examples of each of the technologies identified in the Ruling indicating they do not require five years or more to build and construct. Recent examples of geothermal construction are sparse, but Fervo Energy has constructed or is constructing several projects, including the Cape Station project, which has a timeline from groundbreaking to initial delivery of under four years.[16]

In addition, the Commission should use the additional criteria to determine if a resource should be procured via central procurement:

- Requires upfront commitments and investments in the development of additional non-transmission infrastructure/unique transmission infrastructure;
- Has significant potential for economies of scale that cannot be captured by selling off projects to several off-takers; and
- Removes barriers that prevent other LSEs from conducting similar procurement.

These criteria focus on ensuring that central procurement will accelerate the required transmission or regional infrastructure needed to spur the development of emerging technologies while supporting, not interfering with, ongoing LSE procurement.

d. The Commission Should Not Direct Central Procurement of OOS Wind, Geothermal, and LDES as They Do Not Meet the Criteria for Central Procurement

The Ruling's qualitative analysis of the criteria in Figure 1, as supplemented and modified by the observations in sections 1.a., 1.b., and 1.c., above, leads to the conclusion that some large-scale OSW in the federal leased areas is the best potential fit for centralized

[16] The Cape Station project broke ground on September 25, 2023, and will begin delivering in 2026: https://fervoenergy.com/fervo-energy-breaks-ground-on-the-worlds-largest-next-gen-geothermal-project/.

procurement. The other identified resource types are not good fits for centralized procurement for the reasons described below, and the Commission should, therefore, refrain from directing DWR to procure them.

Offshore Wind: Of all the resource types identified as potential candidates for central procurement, OSW is likely the most compatible with central procurement. It is an emerging technology LSEs have not yet begun contracting for yet, that requires unique transmission infrastructure and investment in port infrastructure to prompt resource development. Before ordering central procurement of OSW, however, the Commission must:

- Protect against excessive customer costs by focusing on procurement that has demonstrated net benefits relative to procurement by LSEs of other combinations of resources with the same profiles.
- Consider the likelihood of DWR's ability to successfully procure OSW at this time, given the challenges with procuring OSW identified in the Ruling that exist regardless of the procuring entity[ies].[17]
- Recognize that LSEs are interested in a pathway to procuring OSW themselves, as represented in CC Power's MOU with CADEMO,[18] and minimize interference with LSE procurement efforts.

OOS Wind: The Ruling correctly identifies OOS wind as a resource that LSEs have demonstrated the ability to self-procure.[19] Given that LSE demand for the resource is already high, the Commission's concern that additional centralized procurement will hurt competition and increase California ratepayer costs is real and warranted.[20] Furthermore, OOS does not

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[17] Ruling, at 8: "There may be many reasons why LSEs have not yet procured OSW projects, including insufficient port development, lack of turbine fabrication infrastructure, lack of installed offshore transmission infrastructure, or under-developed interconnection and permitting processes to accommodate OSW projects. These reasons may be compounded by the nascent global deployment of floating OSW technology, which may have culminated in developer bids that LSEs deemed to be unfavorable to their ratepayers."

[18] *California Community Power and CADEMO Execute Offshore Wind MOU*: https://cal-cca.org/california-community-power-and-cademo-execute-offshore-wind-mou/.

[19] Ruling, at 6.

[20] *Id.*, at 24.

appear to be eligible under AB 1373 since interconnection and transmission development are separate from the resource's construction and development, and there is no evidence that OOS wind cannot be constructed and developed in under five years. In addition, many OOS wind resources' first point of interconnection may not be part of the California Balancing Area Authority, a requirement of AB 1373.[21]

The serious commitment of LSEs to procure OOS wind is demonstrated in the viability of the subscriber PTO model—where LSEs see the resource as viable even with the full burden of the transmission infrastructure cost. The serious commitment of LSEs to procure OOS wind is demonstrated in the viability of the subscriber PTO model—where LSEs see the resource as viable even with the full burden of the transmission infrastructure cost. The Commission should send a clear signal that LSEs have the procurement responsibility for OOS wind to prevent OOS wind developers from reducing participation in LSE procurement efforts due to the prospect of central procurement.

Geothermal Resources: CCAs have demonstrated LSEs' ability to self-procure geothermal resources, with several CCAs reported to have entered contracts in recent years.[22] Supply of geothermal capacity is limited, however, and the industry is still responding to the high level of demand that Commission procurement orders and changing California market conditions have catalyzed. Adding demand beyond the existing 1 gigawatt of Commission-ordered procurement at this time is likely to further increase costs for ratepayers without meaningfully increasing the near-term supply. The Commission should again send a clear signal

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21 Cal. Pub. Util. Code § 80810(c).

22 Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and Mid Term Reliability (MTR) D.21-06-035 Procurement: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/publicirpcompliancereport080123.pdf.

that LSEs have the procurement responsibility for geothermal capacity. This will ensure developers have the right incentives to offer their geothermal capacity in LSE RFOs rather than waiting for uncertainty around CPE procurement opportunities to be resolved and further delaying the development of these resources.

LDES: CCAs have also demonstrated the ability to procure LDES to meet their MTR requirements. As the Ruling notes, "...overall many LSEs already have resources that meet their share of [LDES and clean firm resource] requirements under contract and may be in the process of contracting for more such resources."[23] As of their August 2023 compliance filings, CCAs procured 116 percent of their LDES MTR requirements in aggregate.[24] The Commission should, therefore, not consider LDES for the September 1, 2024, need determination. If in the future, emerging LDES technologies become available and meet the criteria identified in Section 1.b. and 1.c. above, the Commission can consider those in future need determinations that are coordinated with the Reliable and Clean Power Procurement Program (RCPPP).

2. Should other resource types (beyond OSW, OOS wind, geothermal, and LDES) also be considered for centralized procurement through DWR at this time? Provide rationale if you suggest other resources should be included.

As described in response to question 1, the Commission should not consider central procurement of OOS wind, geothermal, or LDES. Likewise, the Commission should not consider other resource types for central procurement. Central procurement should be limited to only those resources that have significant barriers that (1) prohibit any one entity (or a small number of joint entities) from procuring and (2) can be overcome by shifting the procurement responsibility from the

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23 Ruling, at 24.

24 *Summary of Compliance with Integrated Resource Planning (IRP) Order D.19-11-016 and Mid Term Reliability (MTR) D.21-06-035 Procurement*, at 42: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/publicirpcompliancereport080123.pdf.

LSEs to DWR. The Commission should only consider technologies not yet proven on a larger scale, where initial DWR procurement would enhance market transformation and reduce the cost of entry for LSEs, for central procurement.

The DWR should not procure commercially viable and established resource types. The Commission should not include resources that LSEs have demonstrated they can procure, or whose only limitations are those that would also limit CPE procurement (e.g., resource availability, transmission limitations, etc.), in the list of eligible CPE technologies.

For the initial September 1, 2024, statutory requirement, if the Commission finds a need, the Commission should direct the procurement of a limited amount of OSW only. This is the only resource the Commission has conducted an in-depth analysis on and that meets the criteria discussed in response to Question 1. The RCPPP can consider future central procurement needs in a more fully developed procurement framework following the initial September 1, 2024, need determination.

3. In addition to the list of criteria for eligible resources in the AB 1373 statute, are there additional criteria that should be taken into account by the Commission when determining which resources should be procured through the DWR centralized procurement mechanism? Specify.

See response to Question 1 for additional criteria that the Commission should consider. In addition to the criteria above, DWR will need to determine the feasibility of its procurement based on responses to its solicitations. OSW seems like a potential candidate for central procurement, but the OSW industry is so young that DWR may find it infeasible from a risk or affordability perspective to sign contracts at this early stage.

The Commission should incorporate the affordability metrics used to approve project and program costs by their impacts on customers into its procurement decisions. This would require a rigorous analysis of the impact of DWR procurement on overall costs and the increase in customer bills that would result. In addition to the current affordability metrics (Affordability Ratio, Hours at

Minimum Wage, CalEnviroScreen),[25] the Commission should consider the value of market transformation, a metric that should weigh the benefits of long-term cost reductions achieved through market transformation with project costs passed on to customers. This analysis will also require substantial evidence in the record estimating the expected cost reductions in the global market for those technologies resulting from the marginal increase of capacity expected to be procured by California LSEs and DWR. Although it is very unlikely an emergent technology that has yet to be procured by LSEs will be considered cost-effective if simply compared to existing resources, a declining cost model should act as a one guardrail to ensure that customers and the grid will benefit from DWR projects.

4. AB 1373 contains specific criteria for eligible pumped hydroelectric facilities. What particular projects currently under development can meet the criteria and should they be procured centrally by DWR?

CalCCA has no comments at this time but reserves the right to respond in replies.

5. How could developers leverage the many incentive opportunities that are available from the Federal government through the Inflation Reduction Act and the Bipartisan Infrastructure Law to assist with the financing of LLT resource development? How could developers and contractors access the Department of Energy or other agency grants for resource and infrastructure development that are available for projects that improve reliability and grid flexibility? How might centralized procurement help leverage federal funds for each resource type?

It is not yet clear whether centrally procured resources will have a better chance of obtaining grants and other sources of federal funding than resources procured by LSEs. If the Commission orders central procurement, however, the ability to obtain these funds will be a critically important

[25] Decision (D.) 20-07-032, *Decision Adopting Metrics and Methodologies For Assessing the Relative Affordability of Utility Service*, R.18-07-006 (July 16, 2020), established adopted three metrics to assess the affordability of residential electric, natural gas, water, and communications services: "1) the hours at minimum wage required to pay for essential utility services, 2) the socioeconomic vulnerability index of communities in California, and 3) the ratio of essential utility service costs to non-disposable household income – known as the affordability ratio.": https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M344/K049/344049206.PDF.

element of ensuring DWR can affordably accomplish market transformation. The DWR should have dedicated staff members or consultants who investigate grant opportunities and assist potential project developers in reducing costs to maximize the use of funding opportunities in its centralized procurement efforts.

3.1 Cost-Benefit Analysis

6. Comment on the cost-benefit analysis conducted, including the analysis presented in the slide deck posted on the Commission's web site. Does the analysis serve as a reasonable basis for a need determination? Specify how and why.

The OSW cost-benefit analysis documented in the Ruling is an excellent example of modeling uncertainty to inform robust decisions. The Commission should strive to use such quantitative analysis in its implementation of legislative mandates like AB 1373. Some assumptions behind the benefits side of the equation are somewhat opaque and require clarification before parties can opine whether the assumptions have merit, including:

- Data from the IRPs used in the analysis is not up to date (e.g., it does not include the SunZia OOS wind project) and may meaningfully impact results.
- The optimistic cost scenario is not likely to come to fruition in the near term absent significant government subsidies (e.g., Earthshot targets appear to be the end-goals intended for technologies when they are no longer emerging).
- The analysis assumes NREL's ATB cost assumption is defined as conservative, rather than the median, despite being the most current and robust cost assumption available.

Given the September 1, 2024, timeline for need determination, it is likely not feasible for the Commission to update the analysis. However, relying on data from IRPs that are not up to date could meaningfully impact the results of the need determination. The Commission should, therefore, consider these more up to date contracted resources when making its determination of need. Additionally, the observation that concentrating too heavily on OSW has considerable cost and risk should inform the level of upfront commitment. The Commission should start planning infrastructure to accommodate scenarios with lower OSW build but allow opportunities to decline to move forward with DWR contracts if the scenarios and costs do not come to fruition in offers. Finally, the Commission should consider that a proper evaluation of the statewide portfolio need under section 454.51(a) may not be possible at this time. Evaluating state needs takes significant time, and if the current analysis is not adequate, the Commission can opt not to find any need at this time and reevaluate a need during the more rigorous portfolio evaluation during the next IRP cycle.

7. Are the quantities of resources contained in the PSP portfolio adopted in D.24-02-047 a reasonable basis for considering utilization of the centralized procurement mechanism? Provide your rationale.

The Preferred System Plan (PSP) quantities are informative for assessing the potential role of central procurement, but the PSP is still subject to several significant risks and uncertainties. First, the PSP portfolio is based on LSE's 2022 IRP data, which is now outdated. The under-contract, expected online, and forecasted resources presented in Table 1 of the Ruling are also outdated.[26] The Commission should update the portfolios in Table 1 to utilize the most recent procurement data from LSEs.

Second, LSEs were directed to use the cost information provided by the Commission in their 2022 IRPs; those cost trajectories, especially for OSW, have substantially changed since then. The Commission should ensure that, if it directs DWR to procure OSW, it retains the flexibility to adjust the quantity of procurement downward if costs reflected in bids do not result in net benefits at this time.

Finally, the current capacity LSEs have under contract is not an accurate measure of LSEs' plans to procure capacity for needs 10-plus years forward. It is not typical industry practice to procure so far in advance. This means that if the Commission analyzes central procurement needs based only

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[26] Ruling, at 13.

on procured capacity rather than procured *and* planned capacity, it will always signal a need for central procurement. Acting on an apparent need that ignores LSEs' plans would interfere with LSEs' future procurement or result in duplicative procurement. Additionally, the Commission will have a difficult time fairly allocating costs and attributes for resource types that LSEs already have under contract. The Commission should, therefore, use LSE contracted capacity and LSE plans to assess needs and focus on central procurement that will support LSEs' ability to realize their plans through their own procurement.

8. What need determination for centralized procurement should the Commission make before the September 1, 2024 AB 1373 deadline and why? Specify which resource types, in what amount, and by when.

Prior to making any need determination, the Commission should update its analysis based on the most recently available monthly procurement status reports or a separate data request instead of relying on 2022 IRPs. Alternatively, the Commission should defer any need determination until the next IRP cycle when more up-to-date information will be available. Updated procurement data will show far higher amounts of LSE procurement of OOS wind forecasted through June 2028 than represented in Table 1 of the Ruling.

Even without those updates, the information provided does not appear sufficient to inform any need determination by September 1, 2024. As described in response to Question 1 and Question 2 above, OOS wind, geothermal, and LDES are not eligible for central procurement. The Commission should dismiss them as possibilities to better position LSEs to procure them at a competitive price. For OSW, the Commission must include in its analysis a consideration of the tradeoffs of contracting at different stages of project maturity. As demonstrated in the recent uptick in OOS wind procurement following transmission approvals, the reason LSE contracting may be lagging is that the projects are not suitably mature for a contract—whether with an LSE or central entity.

The Commission should only order central procurement for clearly demonstrated needs that will provide net benefits for California customers. Because the Commission's analysis does not demonstrate a clear need at this time, the Commission should revisit central procurement in future IRP cycles in coordination with the RCPPP so that the Commission does not rush into a central procurement order with significant risks, as described in response to Question 14.

If any need for central procurement is identified, it should be limited to the minimum amount of OSW in federal leased areas needed to establish the requisite infrastructure to kickstart OSW generation. The Commission should: 1) ensure the initial quantity is such that any potential CPE failures to contract or project delays do not risk reliability requirements or clean energy targets, 2) consider, if only qualitatively, the impact of OOS wind and any other LSE LLT procurement not yet modeled, and 3) require DWR to defer procurement if it cannot find viable bids (including tax incentives) at costs aligned with the scenarios justifying procurement in the cost-benefit analysis.

9. What other elements of future Commission need determinations (such as the scope of analysis, cost assumptions, ways to manage uncertainty) would provide the best foundation for a centralized procurement solicitation?

The need determination process must be a public stakeholder process, including opportunities for stakeholders to participate in developing and reviewing different scenarios. Ultimately, central procurement needs assessments must allow the Commission and stakeholders to answer the following: Are the costs and risks associated with central procurement less than the costs and risks of substitute resources with the same profile procured by LSEs? If the answer to this question is no, central procurement should not be utilized.

4.1 Integration

10. Is the rationale described above for DWR centralized procurement to be used for new uncontracted resource types, such as OSW, as a public good for GHG reduction purposes reasonable? Why or why not?

No. As stated above, the Commission must ensure it adheres to the statute when establishing the central procurement process and making central procurement decisions. Nowhere in the enabling statute is central procurement contemplated to be used as a public good for GHG reduction purposes. Central procurement must only occur with an established and justified need and benefit as established in section 454.51(a). That is, the Commission must only call upon central procurement in circumstances where there is a clearly identifiable need for additional capacity beyond that planned for by LSEs and the social benefit-cost ratio significantly exceeds the private (developer + LSE) benefit-cost ratio. These circumstances will likely only occur in the beginning tranches of emerging technologies like OSW, where a lot of investment in public infrastructure (e.g., ports, specific transmission needs, specialized equipment manufacturing) is required and where LSEs and developers themselves cannot exclusively capture the benefits. However, they may also occur in circumstances of elevated risk of completion of the project, meaning that whether LSE or centrally procured, there is a significant risk that the resource will not reach commercial operation.

The Commission must recognize the "genuine desire on the part of LSEs to help develop the OSW resource" and other LLT technologies.[27] The CCAs know that early adoption of these technologies in the near term is needed to bring costs down over the long run, just as the solar, wind, and battery industries benefitted from. CCAs continue to conduct procurement activities to support those newer industries (e.g., geothermal and LDES procurement and OSW requests for information). Lack of contracting is not due to a lack of desire but because the OSW developers are not ready to contract because they do not have complete information about their costs (e.g., floating platforms, supply chain, and lack of port infrastructure in California).

[27] Ruling, at 22.

CalCCA agrees with the ruling's statement that it is reasonable to broadly "share the cost, timing and technology risks of development" associated with OSW.[28] However, the benefits of broadly sharing costs and risks do not by themselves make the resource a public good. The central procurement of OSW may have some positive externalities, including lower subsequent costs for LSEs who procure such resources. However, as GHG-free resources create a defined quantity of clean energy, they do not meet the common definition of a public good as non-rivalrous and non-excludable. The attributes of clean energy resources have a defined market value which those who pay for this procurement – California ratepayers – should benefit from.

11. If DWR centrally procures undeveloped resources as a public good, how should that procurement relate to the individual LSE procurement (existing resources under contract and/or future procurement)?

The Commission must exercise caution to avoid direct (or anticipated) competition between LSEs and DWR for procurement of the same resources, scarce interconnection deliverability, or transmission capacity. It can accomplish this by pursuing uncontracted resource types like OSW and staging central procurement within the RCPPP in a manner that considers past LSE procurement and informs future LSE procurement. Failing to do so will introduce risk to LSEs that are actively exceeding procurement targets.

The Commission should not direct DWR to procure undeveloped resources as a public good. It should instead focus on procurement driven by a clearly demonstrated need. Once the Commission identifies a need, it must afford LSEs the opportunity to procure themselves to reduce their allocations of central procurement. Additionally, the RCPPP should credit LSEs that individually procure resources and reduce their cost/benefit allocation from centrally procured resources. Central procurement orders should occur well ahead of when an LSE would solicit its own solicitations for an

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28 *Id.*, at 23.

identified need in RCPPP, ensuring room in LSEs' portfolio for central procurement and their own procurement. Finally, the Commission must allow LSEs to sell the attributes associated with their central procurement allocations to create market liquidity – the ability of the LSE to optimize its portfolio is in itself a customer benefit that would promote customer affordability. Given California's affordability crisis, there is little justification for restricting LSEs in ways that place ever greater burdens on ratepayers.

12. How should any DWR centralized procurement relate to the eventual RCPPP design, given that the Commission has not yet adopted an RCPPP design and yet must make an initial need determination by September 1, 2024?

As described in response to Question 11, the Commission must consider central procurement within the RCPPP to ensure coordination between DWR and LSE procurement efforts. The Commission should account for DWR central procurement activity in the RCPPP need determination and allocation process such that DWR does not take on procurement responsibilities LSEs already plan to fill, and LSEs' procurement needs are discounted by the amount of CPE allocations they will receive. This way, DWR and LSE procurement will not be duplicative.

Given the Commission has not yet finalized or implemented the RCPPP design, coupled with the lack of certainty of successfully bringing OSW to commercial operation even with central procurement, the Commission should limit the use of the CPE now, and align the two types of procurement – RCPPP procurement and central procurement – including need determination, need allocation, etc. The Commission will have further opportunities to evaluate the need for central procurement after it implements RCPPP to ensure that the two processes work effectively together.

13. This ruling proposes that LSEs not be allowed to opt out of DWR centralized procurement requested by the Commission. If you disagree with that proposal, explain why with citations and discussion of relevant provisions of AB 1373.

The Ruling makes an error by proposing that LSEs would not be able to opt out of DWR centralized procurement and failing to discuss the opportunity for LSEs to self-procure afforded in AB 1373. Instead, after the Commission identifies a need for central procurement, CCAs must have an opportunity to procure prior to DWR contracting based upon the Commission's identified need. AB 1373 authorizes the Commission to request DWR to procure needs identified under section 454.51(a), but in section 454.51(d), CCAs have a statutory right of self-procurement. Thus, the Commission makes a legal error in not providing for this right of self-procurement. This reading is also consistent with the spirit of AB 1373. Section 454.52 states "[w]ithin six months of determining that there is a need for the procurement of eligible energy resources, the commission may request the Department of Water Resources to exercise its central procurement function[...]."[29] The August 31, 2023, Senate Committee on Energy, Utilities and Communications Analysis for AB 1373 indicates, "[t]he intent for the six month window is to allow other LSEs the opportunity to procure their fair share of their load if they elect to do so."[30] Therefore, it is not a question of opting-out of procurement, but rather following the intent of AB 1373 and providing LSEs the right to procure ahead of DWR.

14. Should a need determination for DWR centralized procurement be made by the Commission during every IRP cycle during the consideration of the PSP or at some other time? Explain the rationale for your preferred approach.

Yes. The Commission should regularly consider the cost-benefit ratios for the central procurement of only emerging technologies as part of each IRP cycle. Need determination should be based, at a minimum, on LSEs' IRP schedule, utilizing the most recent publicly available procurement status reports to inform need and allowing LSEs ample time to factor in central procurement into their own IRP plans and procurement efforts. Due to the risks

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29 Cal. Pub. Util. Code § 454.52.

30 AB 1373 Senate Committee on Energy, Utilities and Communications Bill Analysis (Version Aug. 31, 2024), at 14.

associated with projects such as OSW, planning efforts should allow for a least-regrets approach (e.g., pursuing needs that appear over multiple planning cycles, allowing for off-ramps if needs significantly change, not over-committing in early stages before technology has become established, etc.). Regularly reconsidering the need for central procurement will allow the Commission to exercise caution for its initial September 1, 2024, need determination, given a need has yet to be identified and the OSW industry may not be ready for contracting, with the understanding it will have future central procurement opportunities.

15. A logical point for POUs to engage with DWR on opting into centralized procurement would be after the Commission makes a need determination, but prior to DWR initiating procurement activities. Comment on whether this is appropriate and include any necessary and relevant implementation concerns or details.

CalCCA has no comments at this time, but reserves the right to respond in replies.

16. If DWR procures resources on behalf of POUs, it is possible that related costs currently socialized through existing processes, such as transmission costs flowing into the transmission access charge (TAC), may be incurred. What other costs of benefits might be implicated, and what is the best means for addressing them?

CalCCA has no comments at this time, but reserves the right to respond in replies.

17. The centralized procurement mechanism could provide an alternative pathway towards procurement of diverse resources that are currently infeasible for individual LSEs or small consortiums of LSEs to develop. What process should the Commission develop to encourage parties, especially developers, to provide candid feedback about timing and pricing considerations necessary to develop LLT resources through this mechanism, while also providing the most value to ratepayers?

Developers are likely only to provide complete and candid information about pricing and timing within the context of an RFP with a procurement opportunity attached. The Commission should seek the latest developer feedback on development timelines, including permitting, procurement, transmission timelines, etc. If the Commission obtains pricing information outside of DWR's RFP process, however, it should consider such information highly uncertain, as the information would not be tied to actual commitments from developers.

5.1 Cost and Benefit Allocation

18. For centralized procurement of resources not yet in LSE portfolios such as OSW, is it appropriate for the costs of any DWR contract to be allocated to all LSEs based on the TAC area's share of a 12-month coincident peak load? If not, provide rationale and explanation for another cost allocation methodology.

Prior to any cost allocation, the Commission should ensure that it does not penalize early actors. It can accomplish this by allocating centralized procurement based on load share, net of LSE procurement of their share of the need. As described in Section II and in response to Question 13, LSEs have a right to self-procure and AB 1373 affords time for LSEs to do so. Those who self-procure should not be allocated the costs and benefits of central procurement. The purpose behind central procurement should be to spur an industry such that LSE-based procurement becomes the normal course of business. Allocating a full cost share to an entity that has already done its own procurement will strongly disincentivize LSEs from procuring early, which will ensure that the only procuring entity is the DWR, and slow evolution to LSE-based procurement.

19. For centralized procurement of resources that already exist in at least some LSE portfolios, what is the appropriate method for allocating costs and benefits?

The Commission should not recommend centralized procurement of resources that LSEs are procuring. The Commission will soon engage with LSEs through the RCPPP, which will establish goals and monitor progress toward procurement of new renewable resources. Before parties can fully develop an answer to this question, the Commission must gain insight into this new RCPPP process. However, as noted in response to Question 18, any allocation of costs to those already procuring resources considered in their RCPPP will likely have the negative consequence of moving all demand for such products to the Commission and DWR.

20. How would DWR's solicitation and contracting process need to change for circumstances where POUs and/or individual LSEs seek additional volumes of procurement beyond the amount of need determination authorized by the Commission? How would those additional costs and benefits be allocated fairly to benefitting LSEs and/or POUs?

At a minimum, if any POUs or individual LSEs request additional volumes, the Commission must ensure that those volumes do not increase the costs to those that have central procurement costs allocated to them but did not request additional volumes. This will mean that either the incremental volumes reduce the average cost of procurement or that the Commission charges incremental volumes separately to those entities requesting the additional volume if the cost is higher than the average.

21. How should the allocation of benefits beyond energy and capacity (such as, but not limited to: RPS value, renewable energy credits, IRP compliance, or GHG-reduction value) be allocated to LSEs?

Any and all attributes of centrally procured resources should be allocated to those that pay for the resource. This would mean that the Commission should provide the LSE for the paying customers with those attributes with no restrictions. The Commission should leave LSEs to manage their portfolio of resources and attributes in the most beneficial and cost-effective manner possible for their customers. In some cases, this may mean selling attributes from a centrally procured and allocated resource to best meet their customers' needs. Therefore, the Commission should allocate all attributes from centrally procured resources to the LSEs whose customers pay for the resources with no restrictions on the LSEs' use of those attributes.

In addition, to the extent central procurement is relied upon to meet obligations, a failure of the CPE should not result in a penalty to LSEs. For example, if RCPPP obligations are set based upon procurement being met in part by the CPE and in part by LSEs, if the LSEs complete their procurement but the CPE does not, the Commission cannot then penalize the LSEs for a failure to meet the procurement assigned to the CPE.

22. How should the AB 1373 requirements for nonbypassable surcharges be implemented?

The answer to this question depends on the method selected for resource and attribute allocation. It is dependent on whether the cost allocation is done by TAC area, statewide (similar to Diablo Canyon Nuclear Power Plant), or through existing DWR non-bypassable charges. Whichever method is selected, it must allocate costs and benefits to all parties for which the costs have been incurred.

23. Some LLT eligible resources may require substantial infrastructure development, the costs of which are incremental to costs related to the deployment of the resource itself (for example, OSW requires port and transmission development; geothermal requires transmission development and construction in challenging environments). How do these contingent, necessary costs influence the overall financial impact of resource development for different eligible resources?

First, the Commission must determine if these infrastructure development costs are separable from the contract itself. Will the state make separate efforts to develop port infrastructure necessary to develop OSW facilities and in doing so, will it charge those development costs to parties other than the OSW developer? If the OSW developer is expected to incur port development costs, the developer would include those costs in their bids. In evaluating the costs and benefits for such projects, the Commission must evaluate costs and benefits correctly to avoid double counting. Similarly, while transmission development may occur, once built, the CAISO process for dispatching the grid may use a different set of resources on the transmission system that was "built for OSW". Any cost-benefit analysis must account for the multiple uses of transmission once built since it is not truly dedicated to a single generator but is dedicated to serving needs and resources on the grid, including imports and exports.

24. How do costs not directly related to the specific energy projects factor

into the affordability question for ratepayers for deployment of LLT resources through centralized procurement? How could centralized procurement help address or mitigate these additional costs?

Central procurement may prove to harm customer affordability if (1) developers are not offering projects to LSEs due to central procurement opportunities, (2) adding additional demand puts pressure on already limited supply, or (3) central procurement efforts are duplicative of or interfere with LSE procurement efforts. In addition, if the CPE fails to meet its procurement responsibility, then LSEs could need to backstop for the CPE, creating a rushed procurement environment and increasing affordability concerns. This would cause significant challenges if LSEs do not have full visibility into the CPE process and, therefore, cannot mitigate the risks of central procurement or lack thereof.

Additionally, the CPE will not help reduce infrastructure costs like transmission, roads, and ports because the CPE itself does not control infrastructure builds. Absent a state or federal funding mechanism, such large infrastructure project costs would show up in contract prices or transmission and distribution costs, impacting affordability to ratepayers. As described in response to Question 5 above, centralized procurement could help address or mitigate these additional costs by taking advantage of all available opportunities for state or federal funding.

6.1 Timeline

25. Is the proposed timeline and activities description appropriate for DWR's initial solicitation activities? If not, what should be the expected timeline and why? What other activities and/or interim milestones should be considered or required?

The timeline and activities described in Table 2 of the Ruling appear generally reasonable for DWR's initial solicitation activities.[31] The Commission and DWR will need to remain flexible with the timing, however. The procurement timing for OSW must coordinate closely

[31] Ruling, at 39.

with transmission and port costs and funding so developers can price their bids with as much certainty as possible on these other potential cost items. The complex process of OSW development requires substantial coordination between state and federal agencies and stakeholders. Assuming the Commission directs DWR to procure OSW resources, the entire process must include a high level of transparency and regular information sharing into the various California planning programs to ensure that progress stays on track.

In addition to regular transparency and information sharing with stakeholders, the Commission should update the timeline to incorporate the "procurement group's" activities described in Question 27. These activities should coincide with DWR's bid evaluation activities so that DWR can submit the procurement group's input along with its proposed contracts for Commission consideration.

The Ruling states that "[i]f necessary, a need determination could also be made outside of the regular process for PSP consideration."[32] The Commission should avoid making central procurement need determinations outside of an established process. Instead, it should establish a regular cadence for determining central procurement needs that fits within the existing IRP process. The Commission should establish such a cadence in a manner that allows it to consider the PSP portfolio, supplemented by the most up-to-date procurement information from LSEs including the June 1, 2024, IRP filings, and make central procurement need determinations with enough time for LSEs to factor those decisions into their individual IRPs.

26. Is there an optimal contract structure for DWR to consider when contracting with resources through the centralized mechanism? Should the Commission review contract structures or other pre-bid activities in advance of their completion?

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[32] Ruling, at 38.

The Commission, in coordination with DWR and other state entities, should explore the viability of different contract structures to maximize ratepayer benefits and balance risk. This exploration should include discussions with federal agencies and experts in federal funding opportunities to better understand how different contract structures would impact federal funding opportunities, including grants, loans, and tax benefits.

Prior to initiating procurement activities, DWR should provide its procurement plan, including timelines and contract structures, on the record so that parties can weigh in before the Commission makes a final determination and DWR begins procurement activities. One critical component of any procurement plan is the potential for off-ramps, such as conditions that would allow the Commission to modify central procurement decisions based upon transmission or port infrastructure build-out, which the state, CAISO, or other entities are responsible for completing.

27. Comment on how the "procurement group" for DWR required by AB 1373 should be implemented.

The "procurement group" should include at least one representative from each LSE type, including IOUs, CCAs, Electric Service Providers, and POUs if the POUs opt-in to use the CPE. Since the DWR is not an LSE nor market competitor, and while CCA customers are paying for the resources, non-market participant CCA representatives should be included in the procurement group. A third-party auditor should evaluate and document DWR's procurement activities with publicly available reporting. The procurement group should be able to communicate concerns about the CPE's procurement activities and recommendations to the Commission for its consideration before the Commission approves CPE procurement recommendations.

28. Is an application the appropriate mechanism for Commission consideration of individual contracts proposed by DWR after the conduct of its solicitation? Explain.

Yes, applications are the appropriate mechanisms for the Commission to consider contracts proposed by DWR. The application mechanism will ensure the Commission thoroughly vets the contracts for just and reasonableness with opportunities for party input. Further, if the actual costs or likelihood of the scenarios with net benefits are not coming to fruition, the Commission should have the opportunity to consider dismissing the application.

29. Include any other process recommendations for the Commission to request or require for DWR's conduct of centralized procurement.

Since the Commission's goals are to spur an industry, the Commission should start by committing to a limited amount of capacity. When coupled with the RCPPP, this will also help to ensure that any risk of CPE failure is mitigated by continuing to procure other renewable resources necessary to meet both state policy and reliability needs. Should the Commission order central procurement, such an order should occur well ahead of when an LSE would conduct its own solicitations so that duplicative and costly over-procurement does not occur.

The Commission should also follow the Ruling's described path forward for evaluating bids the DWR receives. That is, central procurement is, "not intended as a commitment to procure LLT resources at any cost. If the premium required to develop the initial tranche of resources exceeds the portfolio diversity and initial investment values of taking an initial step, the Commission could elect to suspend or postpone the procurement by DWR."[33]

30. Specifically for developers of LLT resources: What would be the optimal timing and minimum threshold amount of a DWR centralized procurement solicitation from your perspective? Explain your rationale. In addition, delineate the categories of costs associated with your projects and when such costs should be firm enough to allow binding bids in a solicitation (for example, due to supply chain issues, components may only be available by a certain date to inform bid development; transmission availability is expected by a certain date; etc.). Be as specific as possible to assist the Commission in designing a reasonable process and timeframe. If desired, information in response

33 Ruling, at 38.

to this question may be requested to be submitted under seal, if supported by relevant justification.

While this question is specifically directed towards developers, CalCCA reserves the right to respond to this question in reply comments based upon its members' experience working with such developers.

31. Assuming that the Commission will give direction to DWR on the expected online date for centrally-procured LLT resources, how might such a directive be framed? For example, should the Commission specify commercial operation by a certain date, by a certain year, or within a range of years?

Should the Commission direct DWR to centrally procure LLT resources, the Commission should order DWR to issue a solicitation and then, like with IOU procurement, approve DWR's proposed procurement only if the Commission finds the contract terms just and reasonable. The Commission should give DWR a range of years that it could procure for depending on an identified need and allow DWR to assess bids with timing as one consideration.

IV. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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

May 24, 2024

JUNE FILINGS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE PROPOSED DECISION

Evelyn Kahl,
General Counsel and Director of Policy
Eric Little,
Director of Regulatory Affairs
Lauren Carr
Senior Market Policy Analyst

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

June 6, 2024

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- The California Public Utilities Commission (Commission) should revise the Proposed Decision to adopt hourly load obligation trading such that it is in place for the first SOD compliance year;

- If the Commission fails to adopt hourly load obligation trading, it must delay SOD implementation or allow for system RA waivers to provide guardrails against excessive RA costs to customers; and

- The Proposed Decision errs by maintaining the 17 percent planning reserve margin under a SOD compliance framework.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	R.23-10-011

CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S
COMMENTS ON THE PROPOSED DECISION

The California Community Choice Association (CalCCA)[1] submits these comments pursuant to Rule 14.3 of the California Public Utilities Commission (Commission) Rules of Practice and Procedure[2] on the Proposed *Decision Adopting Local Capacity Obligations for 2025-2027, Flexible Capacity Obligations for 2025, and Program Refinements*[3] (Proposed Decision), mailed May 17, 2024.

I. INTRODUCTION

The Commission's resource adequacy (RA) program is in turmoil. Supply is scarce, prices are unprecedentedly high, and the Commission expects load-serving entities (LSE) to comply at any cost, administering significant penalties if they do not. At the same time, the Commission and its LSEs are scrambling to test a new RA framework with uncertain compliance tools and obligations. Despite these challenges, the Proposed Decision makes several decisions

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

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

3 Proposed *Decision Adopting Local Capacity Obligations for 2025-2027, Flexible Capacity Obligations for 2025, and Program Refinements*, Rulemaking (R.) 23-10-011 (May 17, 2024).

that neither account for these conditions nor adequately address underlying supply constraints. As a result, it fails to recognize current RA market dynamics, risks RA program affordability, and obstructs LSEs' ability to meet hourly requirements in a cost-effective manner.

The Proposed Decision errs in several respects. First and foremost, the Proposed Decision completely ignores CalCCA's proposal for hourly load obligation trading under the slice-of-day (SOD) framework. It does so despite compelling evidence that hourly transactability will aid in LSE compliance and customer affordability at a time when the Commission should be doing everything it can to help temper electric rates that are overwhelming customers. The proposal garnered significant discussion in the working group and support from a broad range of parties. Still, it is completely absent from the Proposed Decision. The Commission then exacerbates risks to customer affordability by (1) failing to delay SOD implementation or provide for system RA waivers despite its complete disregard for the need to transact at the same level of granularity as the requirement, and (2) adopting a planning reserve margin (PRM) that is higher than the demonstrated need under SOD.

The Commission must remedy the Proposed Decision, which exacerbates RA compliance and affordability barriers. In summary:

- The Proposed Decision puts customer affordability at risk by failing to adopt hourly transactability and dismissing proposals to delay SOD implementation and implement system RA waivers;
- The Commission should revise the Proposed Decision to adopt hourly load obligation trading such that it is in place for the first SOD compliance year;
- If the Commission fails to adopt hourly load obligation trading, it must delay SOD implementation or allow for system RA waivers to provide guardrails against excessive RA costs to customers; and
- The Proposed Decision errs by maintaining the 17 percent PRM under a SOD compliance framework.

Failure to address the extensive issues in the Proposed Decision will perpetuate the dysfunction in the RA program, making it difficult, if not impossible, for all LSEs to comply and driving exorbitant RA prices.

II. THE PROPOSED DECISION PUTS CUSTOMER AFFORDABILITY AT RISK BY FAILING TO ADOPT HOURLY TRANSACTABILITY AND DISMISSING PROPOSALS TO DELAY SOD IMPLEMENTATION AND IMPLEMENT SYSTEM RA WAIVERS

The Proposed Decision completely omits any discussion of CalCCA's hourly load transaction proposal filed on January 19, 2024,[4] presented at the February 14, 2024, workshop,[5] and refined in its February 23, 2024, revised track one proposal[6] and March 8, 2024, comments[7] by incorporating feedback from workshop participants and the California Independent System Operator (CAISO). The Commission must correct its omission by adopting hourly load transactability in time for the first binding SOD RA showing.

A. If Two Compliance Mechanisms are Equally Effective and One is More Cost-Effective than the Other, the Commission Must Choose the Option that is More Cost-Effective

CalCCA's January 19, 2024, proposal included a discussion of the unprecedentedly high RA prices LSEs have paid in recent years.[8] CalCCA is not the only party expressing affordability concerns driven by the RA market. The Commission, the investor-owned utilities (IOU), and the Public Advocates Office of the California Public Utilities Commission (Cal Advocates) have also raised affordability concerns driven by (1) the supply and demand balance, (2) changes in resource counting methodologies, which will change once again under SOD, (3) price increases possibly indicative of market power, and (4) a "comply at any cost" regulatory framework:

- Energy Division (ED): "**Citations and penalties have increased** in recent years, **likely driven by issues related to supply and demand balances** due to resource retirements, load forecast increases, and **changes in resource counting methodologies.**"[9]

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4 *Public Version California Community Choice Association's Comments on Assigned Commissioner's Scoping Memo and Ruling*, R.23-10-011 (Jan.19, 2024) (CalCCA Track 1 Proposal).

5 *Workshop on Track 1 Proposals in R. 23-10-011*, (Feb 14, 2024).

6 *California Community Choice Association's Track 1 Revised Slice-Of-Day (SOD) Proposals*, R.23-10-011 (Feb. 23, 2024) (CalCCA Revised Track 1 Proposal).

7 *California Community Choice Association's Opening Comments on Assigned Commissioner's Scoping Memo and Ruling*, R.23-10-011 (Mar. 8, 2024) (CalCCA Opening Comments).

8 CalCCA Track 1 Proposal at Appendix A.

9 *2022 Resource Adequacy Report*, March 2024, p. 58 (emphasis added).

- <u>Southern California Edison Company (SCE)</u>: "**These dramatic changes to the system will occur amid, and potentially drive further, tightness in the RA market** as delays from new resources persist and uncertainty in **the implementation of SOD framework create greater competition for existing market resources, driving RA prices higher** and increasing the risk of penalties resulting from factors outside LSEs' control."

** Footnote: "In response to a data request, **SCE can supply confidential data** to the Commission **demonstrating the degree to which RA prices have increased** in recent years and **that may also suggest that price increases could be attributable to the assertion of market power**, especially given that energy prices have not seen a similar rise."[10]

- <u>PG&E</u>: "While the Forecast 2024 System RA MPB already exceeds the penalty price and the 2024 net CONE price referenced above, PG&E's forecast of System RA prices are even higher and seem stubbornly resistant to apparent improvements in market conditions."

"[D]ue to recent observed increases in RA market prices and concerns about the health of the RA market within the RA proceeding, PG&E presents a scenario here assuming PG&E's forward curves materialize in the Final 2024 and Forecast 2025 RA MPBs published in the Fall. Under this scenario, the PG&E bundled service generation-related rate would increase 27 percent or $0.042 per kWh, which would have a **monthly bill impact of $23.00 for a typical bundled service residential customer** compared to rates 1 that will be in place as of July 1, 2024."[11]

- <u>Cal Advocates</u>: "**System RA prices in California have reached historically unseen levels** that do not reflect the going forward fixed costs of serving load…. **These prices reflect certain market failures** that include collective action coordination failures and **market concentration effects** that can increase prices for system capacity to levels that exceed system RA capacity penalties. In addition, **reputational risks, the two-year penalty point system, restrictions on LSE expansion,** and potential CAISO backstop costs currently **encourage LSEs to procure system RA at any price."**[12]

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10 *Track 1 Proposals of Southern California Edison Company (U 338-E),* R.23-10-011 (Jan. 19, 2024) emphasis added.

11 *PG&E 2025 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Prepared Testimony*, A.24-05-009, at 2-7, 2-11, and 2-12 (emphasis added).

12 *Residual Capacity Auction Proposal of the Public Advocates Office (Public Version)*, R.23-10-011 (Jan. 19, 2023) (emphasis added) (footnotes omitted) at 2.

There is consensus among these entities that affordability is a major concern. Yet, the Commission refrains from adopting a mechanism (i.e., SOD with hourly obligation trading) that is equally effective from a compliance and reliability standpoint, yet more cost-effective than the alternative (i.e., SOD without hourly obligation trading). The Commission must remedy this by adopting the hourly load obligation trading proposal, which CalCCA has demonstrated:

- Serves a clear need from a compliance and affordability perspective;[13]
- Retains administrative simplicity by validation through existing SOD showing tools;[14]
- Does not interfere with CAISO RA processes;[15] and
- Maintains LSEs' obligations to serve their load, therefore, remaining in adherence with section 380.[16]

B. The Proposed Decision Fails to Protect Customers Against Excessive RA Costs by Ignoring CalCCA's Proposal to Allow LSEs to Transact at the Same Level of Granularity as the Requirement

Without the ability to transact at the same granularity as the requirement, LSEs cannot shape their portfolios to match their obligations. This is because, even though requirements are 24 individual hours, LSEs would need to purchase each resource monthly for all hours it is available, even if LSEs have only one or two hours with open positions. The result will be increased customer costs and artificial constraints on the RA market. CalCCA's analysis has shown that although LSEs can meet aggregate SOD requirements, in some hours, some LSEs are short, and other LSEs are long.[17] Without hourly load obligation trading, the short LSE will either need to procure excess supply, likely at a higher price than it could have done an hourly load obligation trade, that is unnecessary from an aggregate reliability standpoint to satisfy its individual requirements. The alternative is for that LSE to pay a penalty that it could have avoided if it were able to transact hourly with the long LSE. Either outcome is detrimental to customer affordability.

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13 CalCCA Track 1 Proposal at 21-24 and CalCCA Revised Track 1 Proposal at 3-4.
14 CalCCA Revised Track 1 Proposal at 5-6.
15 CalCCA Opening Comments at 3-4.
16 CalCCA Track 2 Proposal at 25.
17 CalCCA Revised Track 1 Proposals at 3-4.

Alternatives to hourly load obligation trading, such as swaps, will likely not allow LSEs to transact in a manner that allows them to shape their procurement to their obligations and, in turn, will not minimize procurement costs ultimately borne by their customers. Swaps involve a trade of one resource for another at a monthly level; while swaps could theoretically reduce SOD deficiencies, in reality, there is too much market friction involved for them to provide significant benefits under SOD. They may require multiple steps to reach compliance for all parties involved. One-for-one swaps between two LSEs and two resources are more likely to simply transfer compliance from one LSE to another, leaving one LSE compliant and the other short. It is also more likely that multiple layers of swaps would be required for each LSE to reach compliance.

There is also less motivation for those holding resources to conduct swaps because they are already compliant and would take on additional transaction costs (in time and money) and potentially take on risk by reducing their excess portfolio that could otherwise be used for substitution. Conversely, there is more motivation for those holding load to transact with each other because the transaction is targeted at the hour(s) and quantity needed rather than finding complex combinations of resource swaps that fulfill both parties' needs.

Allowing transactions at the same granularity as the requirement is the only true way for LSEs to shape their portfolio to their obligation under SOD. The Commission's ignoring the need for hourly load obligation trading fails to protect customers against compounding RA costs. The Commission can resolve this misstep by ensuring LSEs can trade load at the same granularity as the RA requirement.

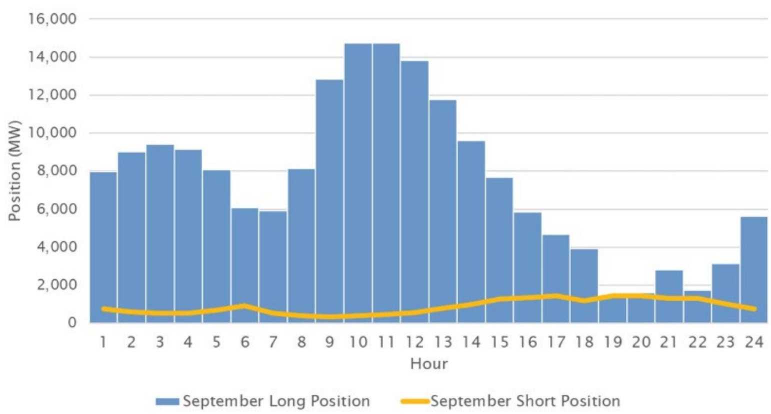
C. The Proposed Decision Errs by Remaining Silent on CalCCA's Hourly Load Transaction Proposal Despite a Compelling Demonstration of Need, Significant Discussion in the Working Groups, and Broad Stakeholder Support

1. Demonstration of Need

The Proposed Decision rejects CalCCA's hourly load obligation trading proposal despite a clear demonstration of the need for transactions at the same granularity as the requirement. CalCCA's analysis of the Commission's SOD report demonstrates that the ability for LSEs to transact load obligations on an hourly basis would have increased compliance with the test year

SOD Year Ahead RA requirements.[18] In fact, on an aggregated basis, long positions could have fully covered short positions in nearly all hours, as shown in the figure below.

Figure 1: SOD Aggregate Short Positions vs Long Positions for all LSEs in September



The data presented in the SOD Report shows that aggregate LSE long positions exceeded short positions in aggregate for all hours except hour ending 19. Consistent with CalCCA's findings from its members' data,[19] trading between LSEs could eliminate nearly all deficiencies. If the Commission reoptimized storage to minimize deficiencies, as CalCCA did in its analysis, the deficiency in hour ending 19 could potentially be eliminated. These findings demonstrate that the hourly load transactability has the potential to minimize or eliminate LSE deficiencies. In short, the system reliability needs are covered in aggregate by the showings of all LSEs even though individual LSEs had deficiencies.

Hourly load obligation trading is especially critical during tight supply conditions. When all or nearly all RA resources are needed to meet aggregate RA requirements as CalCCA and ED's stack analyses suggest, LSEs need the ability to shape resource portfolios to obligations at the same granularity. Under the supply and demand balance LSEs are currently facing, hourly load obligation trading could make the difference between an LSE being compliant or deficient. The Commission should revise the Proposed Decision to remove artificial barriers to compliance to avoid the perverse outcome of penalizing LSEs because they cannot efficiently transact while the system reliability has been met.

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18 *Report on Resource Adequacy Slice of Day Implementation and Year Ahead Showings*, R.23-10-011 (Feb. 5, 2024).

19 CalCCA Track 1 Proposal at 25-26.

2. Discussion in Working Groups

The Proposed Decision also rejects CalCCA's hourly load obligation trading proposal despite CalCCA thoroughly addressing stakeholder questions and concerns following significant discussion in the working groups. First, in response to concerns that hourly obligation trading would add administrative complexity, CalCCA demonstrated that hourly load obligation trading is an administratively simple way to allow transactions at the same granularity as LSE requirements. CalCCA demonstrated how such trades could be documented in the existing SOD showing tool. The LSE paying another to take on its obligation would represent the trade as a megawatt (MW) increase to its RA resource portfolio. The LSE receiving payment to take on the obligation would represent the trade as a MW decrease in its RA resource portfolio.[20]

The Commission could validate hourly load obligation trades by filtering for load sales and purchases, aggregating them, and ensuring the total across all LSEs equals zero. If this validation reflects a discrepancy in how a load obligation trade is documented between LSEs, the Commission should follow the same resolution process as it does today. That is, if an LSE indicates it paid another LSE to take on its obligation, that LSE has the obligation of resolving any discrepancies. CalCCA anticipates LSEs will have contracts with each other to effectuate the trade. The contract should define how LSEs resolve discrepancies. In practice, this is no different than the processes used today to validate RA showings and supply plans. There is simply one more type of "resource" through a load obligation trade than can be shown at present.

Second, in response to parties' concerns about unbundling or impacting CAISO processes, CalCCA explained that hourly load obligation trading is not unbundling because it leaves the obligations and requirements of generators unaffected. Hourly load obligation trading does not involve generators (or their requirements) at all, but rather allows LSEs to contract with another LSE in an efficient manner for both of them to meet their obligations. This eliminates the need to modify CAISO processes like outage substitution or the must offer obligation in any way.

Following the workshop, CalCCA consulted with the CAISO to confirm that the Commission can implement hourly load obligation trading with no CAISO impacts. To do so,

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20 Screenshots of how this would look in the SOD showing tool are presented on slides 141 and 142 of 221: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ra-oir-track-1-workshop----all-slides.pdf.

the Commission would accept and validate hourly load transactions consistent with the process documented in CalCCA's January 19, 2024, proposal[21] and February 23, 2024, proposal update.[22] The LSEs would submit their contracted resources in their RA plans to the CAISO, including all resources shown to the Commission in its SOD showing tool, consistent with the CAISO's showing process under SOD and the CAISO's February 23, 2024, proposal adopted in the Proposed Decision.[23]

Because the CAISO will validate Commission-jurisdictional LSE plans by validating the gross peak hour under SOD, only hourly load transactions that occur during the gross peak hour would have impacts under CAISO RA processes. These impacts can be isolated to the LSEs conducting load transactions and avoid the CAISO entirely. The CAISO validates LSE RA plans against the LSE's load, as communicated through the CEC's load forecast process, plus a PRM. As such, there is no way for the LSE to communicate an hourly load obligation trade directly to the CAISO. This would result in a Capacity Procurement Mechanism (CPM) cost allocation risk for the LSE paying another to take on its obligation in the gross peak hour in the narrow instances when a deficiency *not* related to hourly load transactions occurs.[24]

Third, some parties expressed concern that hourly load obligation trading circumvents Pub. Util. Code section 380(c) requirement that "[e]ach load-serving entity shall maintain physical generating capacity and electrical demand response adequate to meet its load requirements…" These parties considered it an incorrect result to allow another LSE to procure excess and then take on another LSE's obligations for payment. It is incorrect to suggest that hourly load obligation trading runs afoul of section 380. Instead, it maintains the LSEs'

21 CalCCA Track 1 Proposals at 25-26.

22 CalCCA Track 1 Revised SOD Proposals at 5.

23 Proposed Decision at 69.

24 An LSE appearing deficient from a CAISO perspective due to an hourly load obligation trade that the CAISO cannot see should not trigger backstop because the LSE on the other side of the hourly load obligation trade would be required to show to CAISO the resources it is using to cover the additional load that it was paid to take on. In other words, the hourly load obligation trade would keep the system "whole" and should not trigger the need for backstop all else equal. Other deficiencies unrelated to the hourly load trade (e.g., another LSE having an individual deficiency) could trigger backstop, in which case the LSE paying another to take on its obligation would be exposed to backstop cost allocation. To improve the hourly load obligation trading proposal in the long term, the Commission and the CAISO could update their processes such that the CAISO allocates CPM costs to the Commission and have the Commission allocate those costs to LSEs after taking into account hourly trades. Such an update should not be seen as a requirement to implement hourly load obligation trading. Instead, it should be viewed as a potential improvement that could be explored at the CAISO in a future stakeholder initiative.

responsibility to secure enough supply to meet its load requirements. The hourly load obligation trading mechanism does nothing to undermine LSE load obligations; the obligation to serve its customers and the associated costs remain with the original LSE. Moreover, there is no difference between an LSE procuring excess and making that excess available to another LSE through a load transaction than selling the resource itself. The mechanism will operate to trade a long position in a commercial transaction, likely for compensation. CalCCA's hourly load obligation trading proposal would allow one LSE to pay another LSE to take on portions of its RA obligations on an hourly basis and the LSEs would need to document the trade such that the Commission can validate the LSEs maintained sufficient supply to meet their load obligations.

Over the course of a proposal, revised proposal, opening comments, and workshop discussion, CalCCA has thoroughly addressed all concerns with hourly load obligation trading expressed by parties in this proceeding. The Proposed Decision errs by failing to address a proposal that garnered significant stakeholder interest. Given the demonstrated need and substantial benefits the proposal would provide LSEs and customers responsible for paying RA costs, the Commission should revise the Proposed Decision to adopt hourly load obligation trading.

3. Broad Stakeholder Support

A broad range of stakeholders express support for hourly load obligation trading, including direct access LSEs, CCAs, environmental advocates, industry, and some generators.[25] This is demonstrative of the fact that this proposal has no negative impact on any RA market participant, except potentially those who have something to gain from the extremely high market prices that limiting transactability would exacerbate. It promotes the ability of LSEs to meet their obligations in the most cost-effective manner without harming reliability or adding too much administrative complexity.

While the IOUs do not support hourly load obligation trading, they would not be obligated to participate in it. Hourly load obligation trades are voluntary and would only result from willing buyers and sellers agreeing to transact through a contractual arrangement. CalCCA has thoroughly addressed the concerns of the IOUs and other parties, including concerns around complexity and the responsibility of the LSE as discussed in section II.C.2 above. The

[25] See comments filed in R.23-10-011 on March 8, 2024, from the Alliance for Retail Energy Markets, Shell Energy North America (US), L.P., Ava Community Energy, Sierra Club and California Environmental Justice Alliance, Microsoft Corporation, and REV Renewables, LLC.

Commission should modify the Proposed Decision to allow for hourly load obligation trading, as failure to do so would adversely affect customer affordability, result in over-procurement, and jeopardize LSE compliance.

D. The Commission Should Revise the Proposed Decision to Adopt Hourly Load Obligation Trading Such that It is in Place for the First SOD Compliance Year

By neglecting to adopt hourly obligation trading, the Proposed Decision implements a half-baked compliance framework, in which LSEs are expected to comply at any cost but do not have all the tools they need to be successful. A "walk before we run" approach to SOD implementation is unacceptable when customers face compounding affordability challenges and LSEs face significant consequences for RA deficiencies. The Commission must allow LSEs to transact load obligations on an hourly basis beginning with the first binding SOD compliance filings for the foregoing reasons outlined in Section II.

III. IF THE COMMISSION FAILS TO ADOPT HOURLY LOAD OBLIGATION TRADING, IT MUST DELAY SOD IMPLEMENTATION OR ALLOW FOR SYSTEM RA WAIVERS TO PROVIDE GUARDRAILS AGAINST EXCESSIVE RA COSTS TO CUSTOMERS

If the Commission fails to adopt hourly load obligation trading, the Commission must take alternative measures to mitigate against the excessive customer costs and artificial supply strain resulting from the inability to transact at the same granularity as the requirement. The Commission should do so by delaying SOD until at least 2026, or adopting system RA waivers for apparent non-compliance related to SOD implementation issues. The SOD showing tool is currently on version 29, with eight public releases, and LSEs have never been able to complete a test year filing without running into errors with the tool. Still, the Proposed Decision states:

> Energy Division has spent the past year developing and modifying the SOD showing tools in response to party input and will continue doing so in the months following the issuance of this decision. The Commission is confident that the showing tools will be ready for 2025 implementation. However, as we stated in D.23-04-010, we "anticipate that minor adjustments to the compliance tools and program rules may be necessary following the test year."[26]

[26] Proposed Decision at 16, footnote omitted.

Continuing to revise the tool in the months following this decision will leave LSEs uncertain of whether the tool will accurately reflect their SOD position in the binding showings, obstructing LSEs' ability to properly plan and procure for their first binding requirements under a drastically new RA framework. The Commission cannot assume that "minor" adjustments to compliance tools will be, in fact, minor. LSEs have faced continually changing compliance tools where one minor change triggers a subsequent error in the tool. The Commission cannot implement an RA program when LSEs and ED have not been able to successfully submit and validate test year showing with the tools available to them.

In attempting to further justify its decision to move forward with 2025 SOD implementation, the Proposed Decision states that the Commission will "monitor LSEs' compliance with the SOD requirements in 2025 and will consider adjustments to the program as needed."[27] Such an approach is unacceptable when LSEs face severe consequences for non-compliance that incentivize them to procure at any cost and still potentially come up short due to circumstances outside of their control. LSEs must know and understand their obligations *before* being subject to penalties for non-compliance.

CalCCA has been a proponent of SOD given its potential to improve the RA program's ability to ensure reliability under an evolving resource mix. To reach this potential without severe unintended consequences, however, the Commission must ensure the SOD program is not implemented before it is ready. Otherwise, the Commission risks exacerbating uncertainties and compliance risks associated with implementing an RA program that is not fully developed and tested.

If the Commission does move forward with implementing SOD in 2025, especially if it does so without providing LSEs with the ability to transact hourly, the Commission must allow LSEs the opportunity to request a waiver of all penalties, including financial and non-financial penalties, stemming from SOD implementation issues. This should include penalties associated with issues with the SOD showing tool inaccurately reflecting LSEs positions or penalties associated with the inability to transact on an hourly basis. Failure to allow LSEs access to waivers while also limiting their ability to transact leaves customers with no guardrails against excessive RA costs. These costs will come through either over-procurement at extremely high RA prices required to meet compliance obligations with limited transactability or the penalties

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[27] *Id.* at 17.

LSEs face that ultimately get passed down to customers when LSEs cannot find enough supply to meet their obligations despite their best efforts. For these reasons, should the Commission fail to adopt hourly transactability beginning for RA year 2025, it must either delay SOD until hourly transactability can be implemented or adopt system RA waivers for SOD implementation issues.

IV. THE PROPOSED DECISION ERRS BY MAINTAINING THE 17 PERCENT PRM UNDER A SOD COMPLIANCE FRAMEWORK

The Proposed Decision adopts a 17 percent PRM, despite translating the PRM to align with SOD results in a PRM of 15.43 percent.[28] The Proposed Decision errs in retaining the 17 percent PRM for 2025 under SOD for two main reasons. First, retaining the 17 percent PRM while also implementing SOD in 2025 fails to account for the differences between the existing peak demand RA framework and the new hourly SOD RA framework. The PRM is inextricably linked to resource counting rules. Failure to translate the PRM established under the peak demand RA framework and its counting rules results in an inaccurate PRM, which in the case of the Proposed Decision, exacerbates RA supply constraints. The Commission should, therefore, modify the Proposed Decision to ensure the PRM aligns with the resource counting rules used for 2025. That is, if the Commission is intent on implementing SOD in 2025, it must also calibrate the PRM to the SOD framework (i.e., the Commission should adopt a 15.43 percent PRM per ED's SOD calibration).

Second, the Commission attempts to justify its decision to retain the 17 percent PRM by citing the decreased demand in the California Energy Commission's (CEC) 2023 Integrated Energy Policy Report (IEPR) demand forecast compared to previous years, and a shift in the peak from September to July. The Proposed Decision states that retaining the 17 percent PRM "builds in a safety margin in the event the modifications to the 2025 RA forecast do not materialize."[29] Analysis of historical IEPR forecasts demonstrates that it is not uncommon for the demand forecast to swing upwards or downwards year-over-year. The magnitude of the fluctuations can be demonstrated by the year-over-year RA forecast, detailed in Table 1, and the variation in the ratio of the peak coincident load to the peak non-coincident load, detailed in Figure 2. In years 2023 and 2025, for example, the delta with the previous year's forecast is over 1,000 MW but in opposite directions. Conceptually, the year-over-year change in RA

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[28] Proposed Decision at 24.

[29] *Id.*

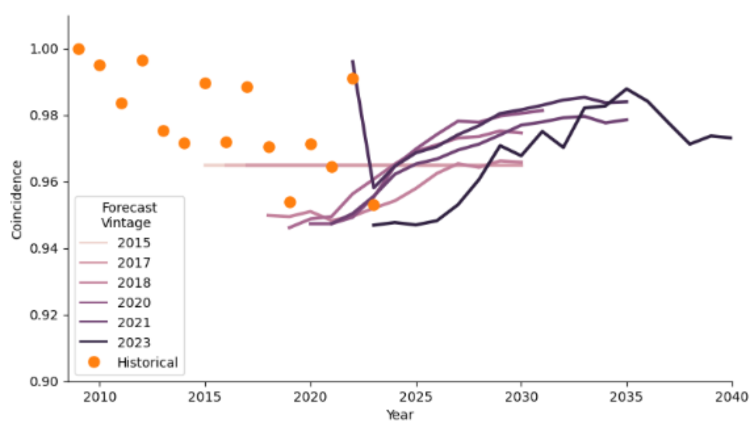
requirements should closely match load growth which has likely not fluctuated this significantly over these years. In fact, examination of the net change in load forecast for 2023 through 2025 reveals an increase of 836 MWs which is significantly above the prior trend.

Table 1: Year-over-Year Change in 1-in-2 RA Forecast[30]

	Year over Year change in Forecast (in MW)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1-in-2 RA Forecast			(636)	(223)	(314)	70	264	1,279	749	(1,192)

The historical ratio of the peak coincident load to the peak non-coincident load, as demonstrated in Figure 2 below, bounces between approximately 0.95 to 1.0. Significantly, a change in the ratio of 0.05 can result in a peak load forecast that changes by as much as 2,500 MW.

Figure 2: Historical Ratio of Peak Coincident Load Relative to Forecast Ratio[31]



These fluctuations have significant impacts on RA requirements and grid infrastructure planning. Rather than building in arbitrary buffers that deviate from the modeled results, the Commission should work with the CEC and stakeholders to (1) evaluate the accuracy of the IEPR demand forecast; (2) identify contributors to forecast errors; (3) solicit suggestions for improving the forecast accuracy; and (4) adjust, if necessary, priorities for continuing to improve the forecast.

30 CalCCA Analysis of 2016-2025 Demand Forecast.
31 CalCCA analysis of CEC historical and current load forecasts.

V. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

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

June 6, 2024

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

4~~**. The Commission is concerned that the reduced demand and shift in peak to July, as reflected in the CEC's 2023 IEPR demand forecast, may result in a restrictively lower PRM for procurement purposes.**~~ Applying a <u>**15.43**</u> ~~17~~ percent SOD PRM for 2025 is <u>**the approach that best accounts for the translation of resource counting from those used under the peak demand RA framework to those that will be used under the SOD RA framework**</u> ~~**a more prudent approach that would help offset uncertainty with the decreased load forecast.**~~

<u>**New: Affordability and reliability are both critical to the electrical market. As such, compliance mechanisms should be established in a manner that enables LSEs to comply as cost-effectively as possible. Load obligation trading is a mechanism that will allow LSEs to comply cost-effectively while maintaining the targeted level of electric grid reliability.**</u>

CONCLUSIONS OF LAW

3. ~~**Considering the 2023 IEPR demand forecast, a 17 percent**~~ <u>**Considering the SOD PRM translation, a 15.43**</u> PRM is a more appropriate PRM to be applied to the SOD framework for the 2025 RA compliance year.

<u>**New: Load obligation trading will produce a reliable outcome while enabling LSEs to meet needs at the least cost alternative.**</u>

ORDERING PARAGRAPHS

5. Beginning with the 2025 Resource Adequacy year, a ~~17~~ <u>**15.43**</u> percent planning reserve margin is adopted to apply to the Slice of Day framework.

<u>**New Order: Beginning with the first binding slice-of-day (SOD) RA filing, the Commission shall allow LSEs to transact load obligations at the same level of granularity as the requirement.**</u>

<u>**New Order: Hourly load obligation trading among LSEs shall be implemented for compliance with the SOD obligation for 2025.**</u>