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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
REPLY COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING
SEEKING FEEDBACK ON MID-TERM RELIABILITY ANALYSIS
AND PROPOSED PROCUREMENT REQUIREMENTS**

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April 9, 2021

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SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

1. The combination of Planning Reserve Margin (PRM), load forecast certainty, and the choice of procurement case (high or low) should not be selected independently without considering the overall desired level of reliability;

2. Evidence supports the ability of load-serving entities (LSEs) other than the investor-owned utilities (IOUs) to work together to procure large resources, making reliance on IOU centralized procurement unnecessary;

3. The counting of resources for compliance must rely solely upon the quantity and characteristics of the resource. The cost should not be a compliance element for any LSE that does not have the California Public Utilities Commission (Commission) as the entity authorizing their cost recovery;

4. The procurement requirement need not account for renewable resources with expiring contracts;

5. Clarification is needed with respect to CONE and how it would be used to set a penalty amount;

6. It is premature to define a zonal need given that the California Independent System Operator (CAISO) is currently conducting a stakeholder process to determine the relative priority of resources using California's transmission system; and

7. Power Charge Indifference Adjustment (PCIA) or PCIA-like protection from the financial impacts of load migration must either be afforded to all LSEs or no LSEs if procurement responsibility is mandated for all LSE types.

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The California Community Choice Association[1] (CalCCA) submits these Reply Comments in response to the *Administrative Law Judge's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements* (ALJ Ruling), dated February 22, 2021 and ALJ Julie Fitch's email dated March 15, 2021, granting Center for Energy Efficiency and Renewable Technologies' (CEERT's) comment extension request: *Opening comments in response to the Ruling will now be due to be filed and served by no later than March 26, 2021. Reply comments will now be due by no later than April 9, 2021.*

I. INTRODUCTION

CalCCA appreciates the opportunity to provide these reply comments. These reply comments address issues raised in opening comments that CalCCA did not previously discuss.

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[1] California Community Choice Association represents the interests of 24 community choice electricity providers (CCAs) in California: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

CalCCA does not change its position on any of the topics that it did raise in opening comments but rather uses this opportunity to expand or address additional issues.

The issues discussed below include:

- The combination of PRM, load forecast certainty, and the choice of procurement case (high or low) should not be selected independently without considering the overall desired level of reliability;
- Evidence supports the ability of LSEs other than the IOUs to work together to procure large resources, making reliance on IOU centralized procurement unnecessary;
- The counting of resources for compliance must rely solely upon the quantity and characteristics of the resource. The cost should not be a compliance element for any LSE that does not have the Commission as the entity authorizing their cost recovery;
- The procurement requirement need not account for renewable resources with expiring contracts;
- Clarification is needed with respect to CONE and how it would be used to set a penalty amount;
- It is premature to define a zonal need given that the CAISO is currently conducting a stakeholder process to determine the relative priority of resources using California's transmission system; and
- PCIA or PCIA-like protection from the financial impacts of load migration must either be afforded to all LSEs or no LSEs if procurement responsibility is mandated for all LSE types.

II. REPLY TO VARIOUS PARTY COMMENTS

A. The Commission Should Not Revise the PRM, Load Forecast Certainty, or Choice of Procurement Case Without Determining the Overall Desired Level of Reliability

Nearly every party addressed the appropriate planning standards for the purposes of the mid-term reliability analysis. Parties' views, however diverged considerably with some advocating for an even higher PRM[2] while others cautioned against the approach taken by staff to determine the proposed PRM, with some taking issue with the adoption of any long-term planning PRM, particularly in light of the lack of robust reliability modeling to support one. Several parties also advocated for increased certainty in load being more directly incorporated into planning standards. [3] In some cases, parties advocated for an even higher procurement target based on each of these elements.[4]

These individual aspects of reliability should not be considered separately; reliability need and procurement must be determined through a holistic process that evaluates the conditions of the grid, including load, transmission, and resources to arrive at a conclusion about the probability of an acceptable level of loss of load (i.e. a Loss-of-Load-Expectation (LOLE)). In its opening comments, CalCCA laid out its proposed process:

> First, decide on a "target" of grid reliability that can be achieved at reasonable cost. Historically, this has been one loss-of-load event every ten years (often referred to as "0.1 LOLE", which is a count of the expected number of loss-of-load events in a given year). However, the CPUC may want to revisit this number (and the underlying weather and load data) to account for climate change or affordability impacts, as well as the increased renewable and battery penetration in the grid relative to when the 0.1 target was first established. Second, calculate the amount of generating resources that are required to achieve this target using a production cost model. Third, divide that amount by the load forecast, incorporating an operating reserve margin adder. The result will be the PRM that should be used.[5]

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2 *See, e.g., CAISO Opening Comments* at 2-3.
3 *See, e.g., CESA Opening Comments* at 6-7.
4 *See, e.g., Vote Solar, The Large-Scale Solar Association, and The Solar Energy Industries Association Opening Comments* at 6-7.
5 *California Community Choice Association's Comments On Administrative Law Judge's Ruling Seeking Feedback On Mid-Term Reliability Analysis and Proposed Procurement Requirements* (CalCCA Opening Comments), March 26, 2021, at A-2.

In other words, the PRM should be an output, not an input, of a robust stakeholder process. Any adoption of a PRM before this process would be premature.

Once the desired level of LOLE (and the PRM derived from it) is known, the Commission can mandate procurement to attain the necessary resources to assure that desired level of reliability. Establishing each of these elements in isolation can result in an unknown level of reliability with associated costs for compliance. This could lead to customers paying for reliability that is beyond the expected need, or inadequate procurement and increased loss of load events. While the abnormal weather conditions in August and September of 2020 cause concern for all stakeholders, the Commission-proposed immediate procurement of 1,800 MW for 2023, in addition to the mandated D.19-11-016 procurement, addresses this near-term need. Procurement beyond 2023, however, warrants new LOLE studies using a production cost model in coordination with the CAISO. Without such studies, the changes to individual elements will - at best - roughly approximate the actions necessary for reliable operation of the grid. The price of guessing, if need is overestimated, will fall to customers in the form of higher, accelerated costs at a time when the Commission is making every effort to maintain affordability for all customers.

B. Joint Procurement is Feasible and Should Be Both Allowed and Encouraged

Both Pacific Gas and Electric Company (PG&E) and The Alliance for Retail Energy Markets (AReM) raise anti-trust concerns and contractual difficulties as the reason to instead require the IOUs to procure for long lead time resources such as geothermal and long-duration storage.[6] PG&E notes that joint procurement by LSEs is not a proven model while noting recent

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[6] *Comments of the Alliance for Retail Energy Markets on Administrative Law Judge's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements*, March 26, 2021, at 11-13. See also, *Opening Comments Of Pacific Gas And Electric Company (U 39 E) To Administrative Law Judge's Ruling Seeking Feedback On Mid-Term Reliability Analysis And Proposed Procurement Requirements* (PG&E Comments), March 26, 2021, at 24.

activities by CalCCA members to engage in joint procurement of large resources.[7] CalCCA's continuing objections to procurement of technology specific resources notwithstanding, the Commission should reject the proposal to have IOUs procure and recover the costs through the cost allocation mechanism (CAM) unless in the event of an opt-out or backstop.

While recent joint procurement among Commission-jurisdictional LSEs may be uncommon, it is simply inaccurate to label joint procurement "unproven". The history of electricity provision has abundant examples of combinations of entities coming together to develop resources. In particular, large resources like hydro and nuclear (*e.g.,* Palo Verde Nuclear Generating Station) were developed jointly by like-minded market participants across multiple states, that included both public agencies and IOUs. Municipalities have long used joint power authorities to procure and provide other services, with the Northern California Power Agency and Southern California Public Power Authority doing so in California. This includes not only the larger projects noted above, but thousands of MWs of recently-developed renewable resources. CCAs have likewise seen the benefit with California Choice Energy Authority (CalChoice) helping to obtain long-term clean energy deals. Most recently, eight CCAs have formed the California Community Power Joint Powers Authority, which is administering an RFO for up to 500 MW of long-duration storage.[8] Similarly, in 2018, San José Clean Energy and Central Coast Community Energy (then Monterey Bay Community Power) signed agreements with vendors to build a total of 328 MW of new solar and wind resources coupled with 40 MW of battery storage, while Central Coast Community Energy and Silicon Valley

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7 PG&E Comments, at 10.

8 https://www.peninsulacleanenergy.com/eight-community-choice-aggregators-partner-to-form-california-community-power-a-joint-powers-authority/ and https://www.svcleanenergy.org/wp-content/uploads/2020/02/RFO-Protocol-Final.docx at 1: "The Joint CCAs are seeking to acquire through one or more LDS Projects up to 500 MWs . . ."

Energy jointly procured a 200MW wind resource.[9] Finally, East Bay Community Energy and PG&E performed joint procurement to meet their coincident needs in the development of the Oakland Clean Energy Initiative.[10]

The Public Advocates Office at the Commission (Cal Advocates) recommends that if an IOU procures jointly with a non-IOU, that the Commission should ensure that costs and benefits be allocated in a load ratio share basis. Such a mechanism, as demonstrated by the Oakland Clean Energy Initiative, is unnecessary and may prevent otherwise valuable contracting from occurring. Each LSE will need to procure a portfolio of resources, and there is no reason to believe that any joint contracting will need to be in a load ratio share basis. Doing so may prevent an otherwise cost effective alternative if it would require one of the parties taking on more capacity than needed to fill their position. Parties can ensure that their customers' best interests are met when contracting individually and jointly, and the Commission will continue to review the transactions of entities subject to its rate jurisdiction in any such joint development. Placing unnecessary restrictions on parties will hamper the ability of LSEs to meet reliability needs while looking out for the best interests of their customers.

Both AReM and PG&E raise unspecified concerns such as "anticompetitive" concerns and PG&E invokes unspecified concerns regarding FERC's market-based rate authorities. While it is difficult to ascertain the precise nature of these highly generalized concerns, certain facts can be provided to clarify this possible issue. First, as it relates to joint CCA procurement, the FERC

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[9] Monterey Bay Community Power Strikes Major Renewable Energy Deal During First Year of Operation (August 1, 2018) https://3cenergy.org/press_release/monterey-bay-community-power-strikes-major-renewable-energy-deal-during-first-year-of-operation/. See also, San José Clean Energy's Credit Facility with Barclays Bank Increases to $80 Million (https://cal-cca.org/san-jose-clean-energys-credit-facility-with-barclays-bank-increases-to-80-million/).

[10] *PG&E Currents*, Apr. 15, 2020, available at https://www.pgecurrents.com/2020/04/15/pge-proposes-two-energy-storage-projects-for-oakland-clean-energy-initiative-to-cpuc/.

has no role in determining whether or not an entity like CC Power would have market-based rate authority. This is because an entity formed under the California Government Code is an exempt entity pursuant to Section 201(f) of the Federal Power Act.[11] While generally a self-evident proposition, given that many publicly-owned utilities are active CAISO market participants and market-based rate authorization is not necessary for that participation, there is specific guidance to remove any doubt the Commission may have. This issue was recently raised in the context of public power participation in the Energy Imbalance Market, and whether exempt entities such as Seattle City Light would need to seek market-based rate authority from the FERC. In a letter from the FERC Office of General Counsel, this issue was clarified to ensure that market-based bids by exempt entities into wholesale markets did not require FERC market-based rate authorization. A copy of that letter is included here as Attachment A.

Perhaps more importantly, beyond the specific issue above, it is also worth noting that all bids, whether submitted by Scheduling Coordinators for CCAs, IOUs, POUs, or suppliers, are governed by the terms and conditions of the CAISO Tariff. This includes bid caps and various market power mitigation provisions. It is difficult to perceive, therefore, what specific concerns AReM or PG&E may have about joint procurement and the impacts on market competitiveness.

Finally, it is not clear how centralized procurement would function in this sense with the Commission having established centralized procurement entities within the PG&E area and Southern California Edison Company (SCE) area but not within the San Diego Gas & Electric Company (SDG&E) area. If a form of centralized procurement were to be performed, it would need to be made clear which entity and under what procurement and cost recovery process the activity is taking place.

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[11] 16 U.S.C. § 824(f) (2012).

For these reasons, the Commission should give LSEs the first opportunity to procure any resource that is required to meet their compliance needs, allowing LSEs to opt-out if they are not in a position to perform their own compliance procurement. In addition, the Commission should not place unnecessary restrictions on the allocation of costs and benefits where parties voluntarily enter into a joint purchase agreement.

C. The Commission Should Set Reliability Based Compliance Requirements

CEERT recommends using a least-cost/best fit approach rather than using the net qualifying capacity (NQC) value of resources.[12] While this methodology may be used for IOU procurement, the Commission does not have jurisdiction over CCA and direct access (DA) providers in this same regard. Public Utilities Code Sections 380(b)(5) and 380(h)(5) clearly afford CCA and DA providers the opportunity to determine the generation that serves their load. CalCCA does not object to performing procurement to meet reliability needs but the least cost/best fit approach is significantly more than defining a reliability need and allowing LSEs to procure to meet that reliability need.

For this reason, the Commission should set reliability-based compliance requirements in terms of the characteristics of resources needed to meet the reliability need which have historically used the NQC value or, within, IRP where the value of wind and solar has been studied as the marginal Effective Load Carrying Capability (ELCC) value maybe acceptable as an interim measure, but new measures more consistent with IRP modeling and reliability

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[12] *Opening Comments of Center for Energy Efficiency and Renewable Technologies on Administrative Law Judge's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements*, March 26, 2021, at 2-3, 6 -8.

valuation should be developed.[13] Indeed, the Commission's own Stack Analysis used marginal ELCC to value the capacity contributions of wind and solar[14]—there is no reason not to use the same values for compliance. While CalCCA believes that better metrics than simple stack analysis and improvements to NQC counting, including net load and energy measurements are necessary in the long-term, the Commission must decide now on what value for a resource will count in compliance with this procurement obligation. Setting that value at the present NQC in the Resource Adequacy (RA) framework and the marginal ELCC value from the Integrated Resource Planning (IRP) is immediately available and a reasonable measure until such time as the IRP and RA processes can develop better metrics for future procurements.

D. The Commission Should Not Increase the Requirements to Account for Expiring Preferred Resource Contracts

The Green Power Institute (GPI) proposes unnecessarily increasing the procurement requirement to account for expiring contracts. GPI states:

> We recommend increasing the amount of preferred resources that are sought through this mid-term procurement effort by the amount of currently operating preferred resources that are coming off contract in the next year or two, and allowing re-contracting with those resources to count towards the procurement targets.[15]

The risks of retirement for preferred resources are significantly different than that of non-preferred resources. Not only do the preferred resources meet reliability needs but they are necessary for Renewable Portfolio Standard (RPS) compliance and are generally sought after by

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13 Decision 18-02-018 Ordering Paragraph 18 required, "Any parties conducting production cost modeling for use in this proceeding shall follow the guidance outlined in Attachment B of this decision." Attachment B at p. 8 specifies, "For this IRP cycle, the Commission directs LSEs to use marginal ELCCs derived from the RESOLVE model's Reference System Plan case…"

14 Stack Analysis, available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442467827 Marginal ELCC values for wind and solar are located in the "ELCC Surface Model" tab, lines 32 and 33. Storage ELCC values are located in the "Storage ELCCs" tab.

15 *Comments of the Green Power Institute on the Ruling on Mid-Term Procurement,* March 26, 2021, at 23.

LSEs looking to exceed California's standards. Indeed, an examination of the CAISO's most recent retirement and mothball list as of April 1, 2021 shows that of the resources listed as 'mothballed' or 'operational' only 92 MWs of the 8,910 MWs are from resources that qualify as preferred loading order resources.[16]

For this reason, the Commission should not change the procurement requirements to account for preferred resources whose contracts will shortly expire as there is a significant probability that those resources will voluntarily be contracted by LSEs to meet other objectives.

E. The Commission Should Not Adopt any Penalty in The Short Term, and Any Future Penalty Must Clarify the Use of CONE

As stated in its opening comments, CalCCA is opposed to any penalty in the short term, due to "the limited availability of resources and limited time to conduct procurement, coupled with the myriad reasons that could produce non-compliant outcomes despite conducting best efforts procurement."[17] However, if the Commission does decide to implement a penalty based on CONE, it must decide on several key issues in order to have meaningful stakeholder feedback on them. Calpine Corporation (Calpine) lays these issues out in its Opening Comments:

> "Does the Commission intend to use net CONE – the levelized cost of capacity net of what the capacity is expected to earn from energy and ancillary services? What proxy resource would serve as the basis for the Commission to calculate net CONE? Would the penalties apply to all years for which procurement is targeted or only for a single year upon the determination that an LSE had failed to procure?"[18]

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16 http://www.caiso.com/Documents/AnnouncedRetirementAndMothballList.xlsx.

17 CalCCA Opening Comments, at A-11.

18 *Comments Of Calpine Corporation On Administrative Law Judge Ruling Seeking Feedback On Mid-Term Reliability Analysis And Proposed Procurement Requirements*, March 26, 2021(Calpine Opening Comments), at 15.

CalCCA agrees with Calpine and echoes its concerns. For example, according to the CPUC Cost-Effectiveness modeling, CONE for a new battery resource is a multiyear strip of costs that varies greatly year over year, ranging from $69/kw-year in 2030 to $444/kw-year in 2050 for batteries.[19] The Commission should clarify if these are the correct values to use, and which of these values it would apply by year, or if another set of values would be used. The ALJ Ruling references "the cost of new entry (CONE) figure published annually by the CEC,"[20] but it is not clear exactly what study this is referring to, and whether this value would differ from the values listed above.

For these reasons, CalCCA recommends that no penalty be adopted in the short term, and that the CONE issues outlined above need to be resolved before any penalty is set based on them.

F. The PG&E Proposal to Consider Zonal Need is Premature

PG&E raises locational concerns regarding new procurement. While locational needs are relevant and important considerations, to include locational requirements immediately is premature. PG&E cites to congestion during the August and September heatwave events concluding "that there was a greater demand for energy in Southern California during the August 2020 heatwave."[21] This ignores the fact that, at the same time, hot weather throughout the Western Electricity Coordinating Council was calling upon power to be transmitted to serve load in a number of different areas. This call included generation from the Pacific Northwest wheeling through California to the Desert Southwest which will also cause the north to south

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[19] ACC Net Cone Excel Model, "Net CONE" tab, row 21. Available at ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/2020%20ACC%20Net%20Cone%20v1c.xlsx

[20] Administrative Law Judge's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements, at 31.

[21] PG&E Comments, at A-2.

congestion noted by PG&E but not necessarily be caused solely by load served in Southern California.

The CAISO is currently making changes to its tariff to change the priority for transmission and has opened a stakeholder process to address this very issue longer term.[22] It is premature to make changes to procurement requirements until the CAISO initiatives are complete and the impact on the availability of California Transmission to meet California load service obligations is more completely understood.

In addition, PG&E's proposal is essentially a zonal stack analysis, comparing loads and resources for the North and South, and concluding that there are shortfalls in the southern region (for example, a shortfall of 2,557 MW in 2021 in SP-26).[23] In addition to the stack analysis, the proposal presents tables of congestion pricing on August 14th, 2020 and August 15th, 2020 (which include some negative values) and Path 26 shadow pricing, arguing that these data show binding transmission constraints on Path 26.[24] This shows that, PG&E argues, "planned once-through-cooling ("OTC") thermal plant retirements create a zonal deficiency and system resource need in Southern California that require resources to be physically located south of Path 26."[25]

Leaving aside the issue of whether or not analyzing the August heat wave days is appropriate to draw any conclusions about zonal loads and resources (a premise CalCCA does not agree with), **<u>any</u>** stack analysis is not a persuasive reason to order zonal procurement. While PG&E is correct to flag the issue of intra-CAISO reliability and transmission constraints, a

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22 California ISO - Market enhancements for summer 2021 readiness (caiso.com) and California ISO - Maximum import capability enhancements (caiso.com).

23 PG&E Opening Testimony Appendix A, at A-1.

24 *Id.* at A-1 through A-5.

25 *Id.* at 2.

production cost model such as SERVM is the best tool for this task—for example, SERVM models PG&E Bay, PG&E Valley, SCE, and SDG&E as four distinct zones with limits between them.

For this reason, the Commission should not adjust the procurement targets for zonal considerations. A production cost model, not a simplified stack analysis, is the appropriate tool for the complex work of modeling intra-CAISO transmission flows. CalCCA already described how this production cost model should be used to determine reliability needs in Section II-A.

G. PCIA Protection from Load Migration Must Apply to All or None of the LSEs with a Procurement Obligation

In their opening comments, PG&E recommended that the Commission afford PCIA protection for migrating load only to the IOU LSEs.[26] CalCCA addresses several of the reasons PG&E appear to rely upon for their recommendation. The first is that load is forecast to migrate away from the IOU to CCAs. While this may turn out to be the case, there is also risk that load migrates away from CCAs to either ESPs or back to IOUs. Regardless, a bi-directional PCIA-like treatment of the costs of the proposed procurement would have no impact on PG&E's bundled customers should the load migration only occur in PG&E's forecasted direction. That is, if all LSEs had a PCIA mechanism and no load migrated from a CCA or DA provider to PG&E, then there would not be any PCIA type of costs paid by PG&E customers as there would not be any customers within that "vintage". If all of the load migration was away from PG&E, then the PCIA costs would follow that load reducing the burden on bundled PG&E ratepayers. In essence, the uniform treatment of PCIA-like protection would simply have costs follow load in whatever direction migration actually occurs as PCIA intended.

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26 PG&E Comments, at 31-32.

PG&E next cites prior joint IOU comments in R.19-03-009 citing to several issues that have yet to be decided within that proceeding. First, PG&E asserts that CCAs already have the ability to charge their customers departing load charges. The Commission and PG&E know that a one-time fee is likely to be a very large dollar amount and an inaccurate forecast of actual stranded costs making this an impractical solution on a customer-by-customer basis. PCIA has been a mechanism to recover above market costs particularly for portions of the LSE's portfolio that extend out many years. At the time that a customer leaves, determining the "out of market" costs on such a forward horizon is fraught with estimation error. This is precisely the reason that the IOUs charge PCIA on a monthly basis as more up to date information on the "out of market" costs are known. While PG&E appears to address this by implying that a CCA can directly bill customers for such costs, it should be noted that presently CCAs do not directly bill customers. In addition, PCIA-like fees are generally billed volumetrically which necessitates relying on billing information that PG&E states cannot be provided due to confidentiality. This leaves a CCA with a single practical option: to bill a potentially large one time exit fee with considerable potential for unknown actual "out of market" costs. With regard to the confidentiality of customer date, since the distribution utility (i.e., the IOU) is the billing agent, there would be no need for IOUs to share confidential information in order to calculate and charge the appropriate customer charges, which means confidentiality is not a barrier to the implementation of bi-directional exit fees.

PG&E argues that the justness and reasonableness of such fees would need to be overseen by the Commission. Such a mechanism would intrude on the rights given to local jurisdiction to set their own rates independent of the Commission. CCAs thus have a right to recover prudently incurred costs even if the prudency of those costs is not reviewed by the same entity as the IOU.

For these reasons, the Commission should either afford all LSEs procuring to meet the reliability need the protections afforded by the PCIA to IOUs for out of market costs or not afford any LSE PCIA protections. Dissimilar treatment based on LSE type will unjustly impact the ratepayers of certain LSEs and must be avoided.

III. CONCLUSION

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

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

April 9, 2021

ATTACHMENT A

FEDERAL ENERGY REGULATORY COMMISSION

WASHINGTON, D. C. 20426

OFFICE OF THE GENERAL COUNSEL

March 23, 2017

Jonathan Schneider, Esq.
Stinson Leonard Street LLP
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Re: General Counsel Opinion Letter—Seattle City Light

Dear Mr. Schneider:

By letter dated February 28, 2017, you requested, on behalf of Seattle City Light,[1] an opinion from the General Counsel of the Federal Energy Regulatory Commission. You asked that I conclude that, as an entity generally exempt from rate regulation by the Commission pursuant to section 201(f) of the Federal Power Act (FPA),[2] Seattle City Light is not required to obtain Commission authorization under FPA section 205[3] to make sales at market-based rates to any purchasers of the following ancillary services: Spinning Reserve, Supplemental Reserve, Energy Imbalance, and Generation Imbalance.

Applicable Law

Section 205 of the FPA applies to "[a]ll rates and charges made, demanded, or received by any public utility . . . in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission . . . ."[4] Section 205 requires that a public utility "file with the Commission . . . schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission. . . ."[5] This requirement, however, while applying to public utilities, would not extend to an entity that is specifically exempted from having to make such filings.

[1] According to your letter, Seattle City Light is a municipally chartered utility that is owned by the City of Seattle, Washington.

[2] 16 U.S.C. § 824(f) (2012).

[3] 16 U.S.C. § 824d (2012).

[4] 16 U.S.C. § 824d(a) (2012).

[5] 16 U.S.C. § 824d(c) (2012).

As relevant here, section 201(f) of the FPA provides that no provision in Part II of the FPA, which includes section 205 of the FPA, shall apply to or be deemed to include "a State or any political subdivision of a State . . . or any agency, authority or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing . . . , unless such provision makes specific reference thereto."[6]

Moreover, Order No. 697, which, among other things, codified the Commission's regulations and standards for market-based rates and established specific market-based rate tariff provisions that are required to be a part of a seller's market-based rate tariff, clarified that "if an entity is specifically exempted from the Commission's regulation pursuant to FPA section 201(f), it would not be considered a public utility under the FPA and, accordingly, would not be required to have a rate on file."[7]

Conclusion

My analysis leads me to conclude that Seattle City Light qualifies for the exemption set forth in section 201(f) of the FPA. Seattle City Light, as a municipally chartered utility that is owned by the City of Seattle, Washington, would be an agency, authority or instrumentality of a State or a political subdivision of a State, or a corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing as provided in section 201(f) of the FPA. That fact, in turn, qualifies it for an exemption from the requirement in section 205 of the FPA to file with the Commission a schedule showing all rates and charges for Commission-jurisdictional services, and thus to obtain Commission authorization to make Commission-jurisdictional sales.[8]

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[6] 16 U.S.C. § 824(f) (2012).

[7] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, at P 214, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied*, 133 S. Ct. 26 (2012).

[8] *New West Energy Corp.*, 83 FERC ¶ 61,004, at 61,015-16 (1998) (finding that because an entity was not public utility as a result of section 201(f) of the FPA, the Commission has no authority under section 205 to accept the entity's rate schedule seeking authorization to engage in Commission-jurisdictional sales of electric energy at

Accordingly, Seattle City Light is not required by section 205 of the FPA to file rate schedules with the Commission for, and thus is not required under section 205 to obtain Commission authorization to sell, the following ancillary services at market-based rates: Spinning Reserve, Supplemental Reserve, Energy Imbalance, and Generation Imbalance.

As provided by section 388.104(a) of the Commission's regulations,[9] the opinions expressed herein are mine as the General Counsel, and they neither bind, nor necessarily reflect the views of, the Commission.

Sincerely,

David L. Morenoff
General Counsel

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market-based rates); *accord*, *e.g.*, *Lee County, Florida*, 157 FERC ¶ 61,218, at P 6 (2016) (*Lee County*); *City of Colton, California*, 145 FERC ¶ 61,026, at P 10 (2013).

However, section 201(b)(2) of the FPA provides that, notwithstanding section 201(f) of the FPA, certain sections of Part II of the FPA, including sections 206(e) and 220 of the FPA, "shall apply to the entities described in such provisions, and such entities shall be subject to the jurisdiction of the Commission for purposes of carrying out such provisions . . . ." *Lee County*, 157 FERC ¶ 61,218 at P 7.

[9] 18 C.F.R. § 388.104(a) (2016).