BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements	)	Rulemaking 16-02-007 (Filed February 11, 2016)

REPLY COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON THE PROPOSED REFERENCE SYSTEM PLAN

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In accordance with the *Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Plan And Related Commission Policy Actions*, dated September 19, 2017 ("Ruling"), the California Community Choice Association ("CalCCA") respectfully submits the following reply comments in the instant proceeding, Rulemaking ("R.") 16-02-007, the Integrated Resource Plan ("IRP") proceeding. In these reply comments, CalCCA addresses points raised by a number of parties in their respective October 26, 2017 opening comments on the proposed Reference System Plan ("RS Plan").

I. INTRODUCTION AND SUMMARY

CalCCA is a nonprofit organization formed in June 2016 to represent the interests of California's Community Choice Aggregation ("CCA") programs in regulatory and legislative matters.[1] Local communities are investigating and establishing CCA programs to customize and accelerate efforts to address climate change, renewable energy development, and other important

[1] The operational CCA programs in California – Apple Valley Choice Energy ("AVCE"), CleanPowerSF, Lancaster Choice Energy ("LCE"), East Bay Community Energy ("EBCE"), County of Los Angeles ("LA County"), Marin Clean Energy ("MCE"), Monterey Bay Community Power ("MBCP"), Peninsula Clean Energy Authority ("PCE"), Pioneer Community Energy ("Pioneer"), Pico Rivera Innovative Municipal Energy

environmental and social issues.

As set forth below: 1) the Commission's IRP process should recognize SB 350's separate IRP process and requirements for CCA programs; 2) this round of IRP should be treated as a test run and should not be used to authorize procurement or make binding planning decisions; 3) early procurement must recognize CCA autonomy and should be approached cautiously; 4) the Commission should monitor GHG reductions through existing compliance requirements, not new, unworkable compliance metrics; 5) the Commission should allow banked RECs to count towards compliance requirements; 6) CalCCA conditionally supports raising the RPS requirement; 7) CalCCA opposes additional non-RPS procurement; 8) TURN's concerns that CCA programs are "gaming the system" are unfounded.

II. REPLY COMMENTS

A. The Commission Should Adopt An IRP Process That Recognizes SB 350's Separate IRP Requirements For CCAs And Respects CCA Autonomy

In opening comments, a number of parties took positions that either explicitly or by implication would violate SB 350, infringe upon CCA procurement autonomy, and unreasonably reduce local energy choice. CalCCA responds to these comments as follows.

i. SB 350 Requires A Distinct IRP Process And Requirements For CCA Programs

In opening comments, several parties, including the Office of Ratepayer Advocates ("ORA"), Natural Resources Defense Council ("NRDC"), California Energy Storage Alliance

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("PRIME"), Redwood Coast Energy Authority ("RCEA"), Silicon Valley Clean Energy Authority ("SVCE"), and the Sonoma Clean Power Authority ("SCPA") – comprise CalCCA's current voting members. In addition, CalCCA's affiliate members include: Central Coast Power (counties of San Luis Obispo, Santa Barbara and Ventura); the cities of Corona, Hermosa Beach, Industry, San Jacinto, San Jose, and Solana Beach; Valley Clean Energy (city of Davis and Yolo County); Coachella Valley Association of Governments; and Western Riverside Council of Governments.

("CESA"), and Large-Scale Solar Association ("LSA"), supported the staff proposal to require that all LSEs, including CCA programs, base their individual IRPs on the Commission's RS Plan and GHG planning price.[2] Several other parties, including San Diego Gas & Electric ("SDG&E"), Southern California Edison ("SCE"), and Vote Solar explicitly argue for reduced CCA autonomy, asking that the Commission impose the same IRP process and requirements to all Load Serving Entities, including CCA programs.[3] Tellingly, in making these arguments not one party acknowledged the separate process and requirements for CCA programs set forth at California Public Utilities Code Section 454.52(b)(3).[4] Nor did any party making these arguments acknowledge that Section 454.51(b), which requires that "Electrical Corporations," not CCA programs, base their individual IRPs on the Commission's portfolio. As discussed in CalCCA's opening comments, SB 350 does not require that CCA programs base their IRPs on the Commission's portfolio or use a Commission-imposed GHG planning price.[5] Any attempt to impose identical requirements on CCA programs and Investor Owned Utilities ("IOU") would be inconsistent with the separate IRP process for CCA programs required by Section 454.52(b)(3).

ii. The Commission Does Not Have Jurisdiction Over CCA Procurement

Several parties, including SDG&E and SCE, argue that the Commission should order CCA programs to procure resources selected by the Commission in IRP.[6] This radical position is entirely unsupported by SB 350. The IRP process outlined in SB 350 is a planning process, not a procurement requirement. Nothing in SB 350 gives the Commission the authority to direct CCA

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2 *See* ORA Opening Comments at 10-12, 15-17; NRDC Opening Comment at 1-2, 4; CESA Opening Comments at 21; LSA Opening Comments at 8-9.

3 *See* SDG&E Opening Comments at 8; SCE Opening Comments at 15-16, 43-44; Vote Solar Opening Comments at 13-14.

4 All further statutory references are to the California Public Utilities Code unless otherwise noted.

5 CalCCA Opening Comments at 4-10.

6 *See* SDG&E Opening Comments at 8, SCE Opening Comments at 15-16.

programs' actual procurement. In addition, attempting to direct CCA procurement would be a clearly violation of Section 366.2(a)(5), which guarantees that each CCA program "is solely responsible for all generation procurement activities on behalf of the [CCA program's] customers, except where other generation procurement arrangements are expressly authorized by statute." Neither SB 350 nor any other statute "expressly" authorizes the Commission to order CCA programs to procure the resources identified by the Commission in its IRP process.

iii. The Commission May Not Impose Non-Bypassable Charges On Existing CCAs For IRP Procurement

A number of parties argue that the Commission should impose Non-Bypassable Charges ("NBCs") on existing CCA programs for IOU procurement authorized in IRP. For instance, LSA recommends that the IOUs procure 3,000 MW of tax credit eligible resources and allocate energy and costs among all LSEs.[7] SCE, somewhat more vaguely, argues that "the costs of any procurement authorized in IRP must be allocated in a fair and equitable manner."[8] The California Wind Energy Alliance ("CalWEA") argues that the costs of resource curtailment should be fairly reapportioned among all LSEs.[9] TURN argues that the Commission should identify one or more entities to be responsible for early procurement, and that the IOUs are currently best positioned to take on this role.[10] CalCCA strongly opposes these proposals.

As a threshold matter, the Power Charge Indifference Adjustment ("PCIA") cannot be used to recover costs associated with IOU's IRP procurement from existing CCA customers. PCIA is an exit fee, not a fee for allocating new costs to existing departing load customers. CalCCA does not dispute that some IOU procurement that is authorized or ordered by the Commission in the IRP and is done on behalf of current bundled customers may, under some

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7 LSA Opening Comments at 3.
8 SCE Opening Comments at 44.
9 CalWEA Opening Comments at 6-7.

circumstances, be eligible for PCIA recovery if those customers subsequently join CCA programs. However, one of the core principles of PCIA is that departing load customers are only responsible for procurement that was done: 1) on their behalf; and 2) *while they were still IOU customers*.[11] Departing load customers are not responsible for PCIA for any IOU procurement as part of an IRP process that was done after those customers joined a CCA program.

In order to protect future departing load customers, the Commission should take all reasonable steps to prevent the IRP process from authorizing or ordering IOU procurement on behalf of future departing load. This would prevent additional future stranded costs created by ongoing IOU procurement and preserve the CCA procurement and planning. At a minimum, these steps should include developing formal departing load projections for each IOU and ensuring that IOUs are not authorized to procure on behalf of reasonably projected departing load.

In addition, the Commission does not have the authority to impose NBCs on current CCA programs for other LSEs' IRP procurement (i.e. through CAM or similar mechanisms), with the single narrow exception of Renewable Integration ("RI") procurement if a CCA program does not self-provide its share of RI resources. CCA procurement autonomy is guaranteed by Section 366.2(a)(5), and the Commission may only infringe on this autonomy – by imposing NBCs – *where it has express statutory authorization to do so*. As discussed in CalCCA's opening comments, when the legislature has given the Commission the authority to impose NBCs on existing CCA programs, it has done so using direct and unambiguous language.[12]

SB 350 does not contain any language that explicitly authorizes the Commission to impose new NBCs on existing CCA programs beyond the narrow RI NBC authorized at Section

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10 TURN Opening Comments at 6.

11 See D.04-12-048; D.08-09-012.

454.51(c–e). The legislature's decision not to authorize a new, general NBC for IOU procurement that may be identified within the IRP process and authorized by the Commission is consistent with past treatment of procurement decisions made and stemming from the LTPP. The purpose of LTPP was to evaluate the need for new resources to meet system and local area reliability needs and evaluate bundled procurement plans and procurement rules applicable to the IOUs. CCA programs were not subject to the Commission's LTPP jurisdiction,[13] and IOU procurement authorized or required through the LTPP was not generally eligible for NBC recovery from existing CCA customers. Because the IRP proceeding is the direct successor of the Commission's LTPP proceeding, it is similarly not surprising to see the legislature declining to expressly authorize the Commission to order procurement by CCAs or impose NBCs on existing CCA customers.

Further, the legislature's decision not to authorize a new, general NBC for the IOU's IRP procurement is consistent with the structure and intent of SB 350. In order to qualify for board approval, a CCA program's IRP must be consistent with the three criteria set forth at Section 454.52(b)(3). SB 350 vests the authority to determine whether a CCA program's IRP satisfies these criteria solely in each CCA's governing board. Thus, each CCA program's board-approved IRP, by definition, contributes that program's share of progress towards SB 350's goals, as determined by its appropriate authority. The submission of each CCA's approved IRP to the Commission for certification by the Commission will provide the Commission with all of the information it needs to utilize the IRP process for planning purposes. Thus, the careful balance struck by the legislature in protecting CCA procurement autonomy while also reforming

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12 CalCCA Opening Comments at 10.

13 *Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements* ("IRP OIR") at 14.

CPUC planning processes by moving to an IRP-based process rather than the LTPP are not at odds. Most importantly, if a CCA's IRP provides that program's fair share of progress towards SB 350's goals, then there is no cost shifting and thus no need for NBCs.

B. The First Round Of IRP Should Be A Test Run

CalCCA strongly agrees with the opening comments of a number of parties that have argued that the 2017-2018 IRP proceeding – the Commission's first attempt to develop an IRP process under SB 350 – should be treated as a "test-run" and should not result in any binding planning decisions or procurement authorizations. This is particularly critical given the requests by some parties that the Commission rely on the model's results to order as much as $6 to $10 billion[14] in new procurement.

Eagle Crest Energy argues that the Commission should recognize the limitations of the model as a "conceptual drawing."[15] The California Large Energy Consumers Association ("CLECA") recommends that "the first cycle of the IRP … be used as a learning exercise."[16] Green Power Institute ("GPI") argues that the first round of IRP should be a "trial run."[17] CalCCA strongly agrees with these parties for three reasons. First, in initiating the 2017-2018 IRP process, the Energy Division itself stated that the process was intended to be a trial run. Second, the sheer number of flaws in the RESOLVE model identified in opening comments demonstrates that the model is not ready to serve as a basis for planning decisions, and should be fully vetted in an initial "test run" proceeding. Third, a number of key questions regarding the Energy Division's proposed Commission IRP process are outstanding, not least of which is

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14 The RESOLVE model uses capital costs in 2018 of $1,908/kW for utility-scale solar and $2,018/kW (with some slight variation by region) for utility-scale wind resources. (Attachment B (RESOLVE Documentation CPUC 2017 IRP), p. 12). Each 1,000 MW of renewable procurement requires a capital investment of about $2 billion.

15 Eagle Crest Energy Opening Comments at 3.

16 CLECA Opening Comments at 9.

confusion over the nature and extent of the Commission's IRP authority over CCA programs. The Commission should not make binding planning decisions in IRP until these questions are resolved.

The Commission's original conception of the first round of IRP was that it would be a trail run, allowing the Commission, Load Serving Entities ("LSE"), to work through the IRP process and associated modeling without the process leading to binding planning decisions. As stated in its Proposal for Implementing Integrated Resource Planning at the CPUC (accompanying the ALJ's May 16th Ruling),

> [Energy Division] Staff proposes that IRP 2017-18 will establish and demonstrate the feasibility of the proposed process. In this round, the Preferred System Portfolio will generally serve to provide non-binding information to individual resource proceedings, which will continue to be responsible for planning and implementing their respective programs.[18]

The Proposal goes on to identify a five step process where the Commission would; 1) set a GHG planning target; 2) Develop a Reference Plan to meet that target; 3) Direct LSEs (subject to jurisdictional limits) to develop IRPs to meet the target; 4) Approve the LSE's individual IRP plans; and only then 5) have the LSEs engage in actual procurement.[19] The Proposal goes on to state that; "Given the complexity of transitioning away from the existing resource planning paradigm, staff proposes that the IRP proceeding's overarching goal in 2017-18 be to establish the essential groundwork and structure for IRP, and to move through the entire process once.[20] Expediting early procurement would have the Commission immediately skip to Step 5 of this process.

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[17] GPI Opening Comments at 1.

[18] Energy Division Proposal for Implementing Integrated Resource Planning at the CPUC, p. 20.

[19] Energy Division Proposal for Implementing Integrated Resource Planning at the CPUC, p. 23.

Having made this representation, the Commission should not change course now and use the model's results to order significant new procurement. CalCCA agrees with PG&E that, as matter of law and fair process, a determination of short-term need, and associated procurement, would require evidentiary hearings.

In addition, a number of fundamental legal questions regarding the Commission's proposed IRP process have not yet been resolved. For instance, CalCCA has challenged the Energy Division's proposed process on the grounds that it: would seek to impose requirements on CCA programs that SB 350 clearly states apply only to electrical corporations; ignores the separate IRP process and requirements for CCA programs set forth at Section 454.52(b)(3); and does not establish a process for identifying each CCA program's share of the renewable integration need or establish the self-provision process required by Section 454.51(c-e).[21] Similarly, in its opening comments, AREM notes that a number of SB 350's requirements *apply only to IOUs*.[22] Until these fundamental questions regarding the nature and extent of the Commission's IRP authority and the degree to which the proposed process complies with SB 350 are fully and finally resolved, the Commission should not rely on the IRP process to make binding planning decisions.

In opening comments, a number of parties have reiterated that the current RESOLVE model is not ready for actual use. AREM notes that "the modeling has limitations and more analyses and refinement is needed."[23] EDF notes that the modeling contains "substantial analytical gaps."[24] GPI argues that the model needs to be subject to a "rigorous uncertainty

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[20] Energy Division Proposal for Implementing Integrated Resource Planning at the CPUC, p. 24.
[21] CalCCA Opening Comments at 5-6, 11.
[22] AREM Opening Comments at 10.
[23] AREM Opening Comments at 2.
[24] EDF Opening Comments at 1.

analysis" rather than just relying on sensitivity analyses.[25] Even parties that support early procurement, such as CEERT, recognize that the model still needs a "thorough vetting."[26] In addition to these general observations, a wide range of parties have identified specific, significant flaws in the Energy Division's IRP modeling. In light of these significant flaws, discussed in detail below, the modeling should not be relied upon to make planning decisions or authorize procurement in this round of IRP.

i. Energy Efficiency Should be Modeled Using the SB 350 Requirements to be Consistent with CARB's SB32 Scoping Plan and the Definition of Baseline Resources

A number of parties, including BAMX, CCSF, CAISO, the California Efficiency and Demand Management Council, and CEJA/SC, argue that the RS Plan should be modeled using the SB 350 energy efficiency requirements as a baseline.

RESOLVE should account the doubling of energy efficiency required by SB 350. The RS Plan states that the RESOLVE model's baseline resources should include the "projected achievement of demand-side programs under *current policy*,"[27] and that the purpose of the plan is to ensure compliance with the California Air Resources Board's ("CARB") Greenhouse Gas ("GHG") emission reduction plans. Despite this, the model's baseline resources *do not* include California's current policy, legislatively required under SB350, that California double its energy efficiency target. Achievement of this goal is one of the GHG reduction measures specifically identified in CARB's latest draft SB 32 Scoping Plan.[28] As the California Efficiency and

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25 GPI Opening Comments at 2.
26 CEERT Opening Comments at 2.
27 Reference System Plan, p. 26
28 California Air Resources Board (CARB) Draft Climate Change Scoping Plan (Scoping Plan) issued October 27, 2017, at 46.

Demand Management Council notes: "A draft report on [how to achieve] the doubling of energy efficiency was released by the California Energy Commission (CEC) on August 28, 2017."[29]

CalCCA agrees with the California Efficiency and Demand Management Council that: "the more energy efficiency that is included in the model the fewer supply-side resources are needed and the greater cost savings are achieved."[30] In addition, fully accounting for required energy efficiency will reduce the risk of overprocurement and stranded assets that would be problematic for future departing load customers.

ii. Existing Gas Plants Should not be Assumed to Remain in Operation

A critical assumption of the RESOLVE model is that, once the natural gas-fired plants in California subject to the Once-Through Cooling ("OTC") requirements retire, all of California's remaining fleet of natural gas-powered plants will remain available over the model's planning horizon. These natural gas plants, in turn, play a critical role, under the model's assumptions, in providing the flexible capacity needed to maintain reliability as the model adds significant amounts of solar capacity to the system.

A number of parties, including Calpine, GPI, and NRG question this assumption, particularly given the uncertainty in the RESOLVE model as to how these units would recover their costs. CalCCA shares these parties' concerns. As ORA states, the RESOLVE model assumes existing gas units are paid the current resource adequacy ("RA") capacity price despite concerns that this might not provide sufficient revenues to keep these plants in operation, particularly as they get dispatched significantly less as the RESOLVE model adds more

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29 California Efficiency and Demand Management Council Opening Comments at 3.

30 California Efficiency and Demand Management Council Opening Comments at 17, citing D.17-08-022.

renewable resources.[31] The Commission has just opened a new RA proceeding to address these issues.

iii. Existing Gas Plants May not be able to Cycle up and Down as Assumed in the Model; and Could Increase Pollution

It is also unclear if existing gas plants can cycle up and down to meet the fluctuations in generation as intermittent wind/solar resources comprise an increasing portion of California's energy portfolio. Even if they could, as CEJA/Sierra Club note, the constant ramping up and down of power plants results in them operating inefficiently, thus increasing the emission of other pollutants.[32] A single start-up of the Colusa power plant, for example, produces the same level of emissions as if the plant had operated continuously for 38 hours.[33]

iv. Export Capability

The ability of California to handle the increasing amount of intermittent renewable resources proposed in the RESOLVE is also exacerbated by the model's assumptions regarding exports. The model assumes that California can export up to 2,000 MW of energy. As the CAISO notes, this represents a 6,000 MW shift in the use of California's transmission system, as California is currently a net importer of 4,000 MW.[34] A change of this magnitude would have to be assessed by WECC, "because there is currently no experience with any level of net exports out of California."[35] The combination of inflexible (or an insufficient amount) of natural gas plants, combined with limited export capability could significantly increase the amount of renewable curtailment forecasted in the model. CAISO believes that this incorrect modeling

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31 ORA Opening Comments at 2.
32 CEJA/SC Opening Comments at 5-6.
33 CEJA/SC Opening Comments at 6.
34 CAISO Opening Comments at 7.
35 CAISO Opening Comments at 7.

explains that curtailment levels are similar (3%, 4%, and 5%) between the model's three scenarios.[36]

v. Out-of-State Resources

As the CAISO notes, the RESOLVE model uses the default emission factor set by CARB of 0.428 tons of GHG per MWh to evaluate fossil-based out-of-state (OOS) resources.[37] As this emission rate is higher than comparable in-state resources, it appears to distort the dispatch of in-state resources relative to these OOS resources.

vi. Other Resources and Repowering

In addition to the above concerns, a number of parties have proposed modifications to the model that they believe better represent the operational and cost attributes of various technologies. Thus, numerous parties have concerns that the RESOLVE model fails to accurately model demand response (ACC, CLECA, EDF, SDG&E), geothermal resources (Calpine, Imperial County, IID, Ormat) and storage costs (California Energy Storage Association).

An additional concern is that the RESOLVE does not appear to have modeled the cost of repowering an existing resource, which could be significantly less costly than building a new resource. Among the resources affected by this change include natural gas-fired generation, geothermal and wind resources. Enabling existing plants to stay on line through lower cost upgrades could also retain significant resource availability.[38]

vii. No Guarantee that Reliability is Maintained

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[36] CAISO Opening Comments at 5-6.

[37] CAISO Opening Comments at 4.

[38] This includes Cogeneration Association of California's 1,685 MW of existing combined heat and power, and California Biomass Alliance's 75 MW of already built but idle biomass facilities.

The CAISO, as operator of a significant portion of California's electric grid, as well as a number of other parties, recognizes that the RESOLVE model's results, on their own, are not sufficient to ensure that the lights remain on and reliability is maintained, and need to be subjected to production cost modeling.[39] CalCCA shares CAISO's concern. A critical criterion of any planning model is that it is designed to produce results that ensure reliable electric service to Californians, something the RESOLVE model is not designed to do. The RESOLVE model is a "capacity expansion" model that is designed to model long-term resource additions to an electric system. This is significantly different from a "production cost model" which models an electric system over every hour of the year to ensure that loads are met and reliability is not jeopardized.

A related flaw is that the RESOLVE model looks at the overall impact of planning and procurement decisions on the state as a whole and does not consider the costs to individual LSEs. Thus the overall State "system" may be optimized, but for individual LSEs, CCAs, and IOUs, additional costs from congestion, curtailment, and other factors are not considered. Therefore, RESOLVE may not provide the most cost-effective result when each individual LSE's costs are aggregated together.

C. Any Early Procurement Must Recognize CCA Autonomy And Should Be Undertaken Cautiously

A number of parties advocate that the Commission should engage in early procurement of significant amounts of renewable energy as soon as possible to take advantage of the federal Production Tax Credits ("PTC") and Investment Tax Credits ("ITC") available for renewable developers – credits that will be phasing out in the coming years. The amounts of "early

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39 CAISO Opening Comments at 2-3.

procurement" proposed by parties range from 3,000 to 5,000 MW.[40] IEP also proposes additional procurement to backfill the planned closure of the Diablo Canyon Power Plant in 2024/2025.[41] Conversely, a number of parties oppose this procurement as premature. For instance, AReM states that any benefits of early procurement "are not assured and may not be appropriately reflected in the model results," and that early procurement "may saddle all customers with higher than necessary electricity prices and additional stranded costs."[42]

As a threshold matter, and as established in detail in CalCCA's opening comments, SB 350 does not give the Commission the authority to require that CCA programs plan for or participate in early procurement identified in the Commission's RS Plan. Nor does the Commission have the authority to impose NBCs for early procurement by IOUs on existing CCA programs. If the Commission does authorize or require early procurement in the IRP process, it must, at a minimum:

1) In accordance with Section 366.2(a)(5), recognize that CCA programs are exempt from being required to include early procurement in their IRPs and/or engage in early procurement identified by the Commission;

2) Recognize that the IOUs may not impose the costs of early procurement on existing CCA programs through NBCs, distribution rates, or any other charge;

3) Not authorize or require early procurement on behalf of reasonably projected departing load; and

4) Require that any authorized procurement be demonstrably cost-effective.

Even if these conditions are met, CalCCA agrees with the concerns raised by AREM and others, and urges the Commission to move forward cautiously and fully evaluate the impact to ratepayers before authorizing or requiring any early procurement. The problems with the

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40 Among the parties proposing increases are CalWEA (5,000 MW); IEP (3,000 MW); LSA (3,000 MW) along with SEIA, CEERT and Silicon Valley Leadership Group (SVLG).
41 IEP Opening Comments at 4-6.
42 AREM Opening Comments at 3.

RESOLVE model identified above, as well as the inherent uncertainty of all modeling based on a single set of assumptions, argue for prudence before authorizing or requiring any procurement. Particularly relevant are questions regarding the ability of California's electric system to incorporate significant amounts of new renewable energy and to accept equally significant increases in renewable curtailment, and the reasonableness of RESOLVE's assumptions that the existing natural gas fleet has the ability to cycle up and down, exported energy can reach levels never before seen in history, and all of the incumbent issues of new contract terms and conditions for developers of the new renewables and cost recovery for the existing natural gas fleet can be resolved and incorporated into the modeling.

Additional concerns with early procurement, as identified by CalCCA and other parties are expressed below.

i. Even RESOLVE Model Concludes That Early Procurement Costs are Incurred Up-front While Benefits are only Realized in the Later Years

As noted by BAMX/CCSF, the RESOLVE model itself recognizes that early procurement would require incurring immediate costs but that the savings are only achieved much later in the planning cycle.[43] Given the small magnitude of savings realized, it is likely that any savings would be more than offset by the inherent uncertainty in the model.

ii. Any Potential Savings Are Tied to Assumptions About Future Solar Prices, the Expiration of the Tax Credits, and Resolution of Tariffs on Solar Imports

The RESOLVE model's conclusion that early procurement is cost-effective is driven by the assumption that cost of current resources, with tax credits factored in, are less than the reasonably anticipated cost of resources procured in the future. CalCCA agrees with the several parties who, in opening comments, challenged this assumption as unreasonable. There are two reasons to question this assumption. First, given the fact that the federal tax credits have been repeatedly renewed in the past, it may be imprudent to make large-scale procurement decisions based on the assumption that the credits will not be renewed or revived at any point between now and the mid-2020s.[44] Renewal of the tax credits would entirely eliminate any benefit from early procurement. Second, even if the tax credits are not renewed, there is reason to believe that the cost of resources procured in the future will be less than current procurement that takes advantage of tax credits. RESOLVE relies on a set of assumptions regarding future resource cost that are significantly higher than generally accepted cost estimates, including estimates from Bloomberg New Energy Finance and Lazard. Using more accurate cost estimates that follow the established trend of declining renewable resource costs due to improved technology, manufacturing innovation, economies of scale, and increased market competition would reduce or eliminate the benefit of advance procurement.

Additionally, any benefits of early procurement are subject to the uncertainty regarding the ongoing dispute over whether the federal government should set tariffs on imported solar equipment. Hence, it may not make sense to make a multi-billion-dollar investment decision based on what a future Congress or Administration may or may not do.

iii. Early Procurement Could Lead to Market Power Imbalances

In opening comments, SCE argues that requiring large-scale under a tight timeframe will create a significant market power imbalance in favor of renewable developers, which would likely allow developers to capture a large portion of the projected savings associated with the PTC and ITC.[45] CalCCA registered a similar concern in its opening comments, noting that

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43 BAMX/CCSF Opening Comments at 5-9.
44 SCE Opening Comments at 26.
45 SCE Opening Comments at 23-24.

requiring the procurement of a significant amount of renewable resources within the short-time period necessary to qualify for full PTC/ITC credits could result in market power imbalance for sellers, thus negating any savings to ratepayers.[46] The RESOLVE model does not account for this significant potential problem, and instead assumes that all of the savings from the tax credits will be passed on to ratepayers.

The CAISO has expressed a similar concern over the ability of California to ramp up and construct such a significant amount of renewable resources in such a short time.[47] As PG&E notes, such significant procurement would diverge from the slow but steady RPS procurement practices that California has adopted.[48] Even if market power by the developers is not a problem, increased demand for other product inputs, such as wind turbines, skilled labor, etc. could also drive up the price of the projects. Requiring that procurement be done in an expedited fashion will almost necessarily detract from its cost-effectiveness.[49]

There is no guarantee that early procurement will deliver the benefits of the tax credits to California rate payers, and it is reasonable to expect that that, in a short-term constrained supply environment, it will not.

iv. Any Procurement Must Be Guaranteed To Be Cost-Effective

Should the Commission decide, despite the above concerns, to proceed with any expedited procurement, it should ensure that all accepted bids are cost-effective. Cost effectiveness must include incorporation of a new operating environment that will require renewable generation to be responsive to system needs such that a "must run" type of contract

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46 CalCCA Opening Comments at 19-20.
47 PG&E Opening Comments at 24.
48 CAISO Opening Comments at 6.
49 SCE Opening Comments at 17.

will not be available and prediction of revenues by developers will become their responsibility. Given these new operational requirements, bid prices must still be cost effective.

Even AWEA, a strong proponent of early procurement, supports this concept (without offering a metric for its determination).[50] In response, CalCCA offers that potential metrics of cost-effectiveness could involve such concepts as: 1) requiring that 100% of all federal tax credits be passed on to ratepayers; benchmarking bids against previous bids in utility RFOs with a requirement that any accepted bid must be some percentage lower; or 2) requiring that any projects selected under this process commit to meeting the price for new projects that come on-line in the 2026-2030 time-period when these projects otherwise would have come on-line. This latter approach would allow proponents of early procurement to commit to ratepayers that the expected savings claimed by early procurement will actually materialize, and assigns the risk accordingly.

In its comments, AWEA also notes that given current wind prices, many developers would be willing to assume within the prices charged in their PPAs, the cost of transmission needed to deliver to California.[51] This provision should also be included in any solicitation.

v. CCAs Are Proving To Be Part Of The Solution To The Issue Of Early Procurement

Even if the Commission decides not to order early procurement, this does not mean that early procurement will not occur. One option for California to gain the potential benefits, if any, of expedited renewable procurement is to recognize the role of CCAs in procuring new capacity. As Calpine states: "numerous new LSEs have short- and long-term procurement requirements

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50 AWEA Opening Comments at 3.

51 AWEA Opening Comments at 7-8.

that could be filled with 'early procurement' without associated excess procurement."[52] AWEA notes the potential for CCA procurement, and suggests that early procurement should be mandated for the IOUs and optional for CCA programs.[53]

The amount of potential load that will seeking renewable energy supplies in the near future could be significant. In PG&E's current Energy Resource Recovery Account proceeding (A.17-06-005), PG&E has identified approximately 7,600 GWh of load from new CCAs forming in late 2017/early 2018, plus significant incremental growth from the expansion of MCE's and CleanPowerSF's operations.[54] Additional departing load is forecast and/or expected to occur in the service territories of Southern California Edison and San Diego Gas & Electric as new CCAs form. All of this load is subject not only to California's RPS requirements but also the requirement, starting in 2021, that 65% of required RPS need to be met from contracts of 10-years or longer. A recent GTM Consulting Report estimated that CCA programs may need to contract for an additional 2.6 of renewable energy by 2022, and that CCA programs may represent up to 45% of California's utility PV demand within the next five years.

D. The Commission Should Monitor Achievement of GHG Reduction Goals by Ensuring Compliance with Existing Requirements, not by Establishing New, Unworkable Compliance Metrics

As noted in CalCCA's Opening Comments (NC):

> The Commission appears to be significantly expanding the scope and purpose of the IRP process…In preparing these IRPs, the Commission was to ensure that LSEs meet the "GHG emission reduction targets established by the State Air Resources Board" to meet AB32 and SB32 requirements. SB32, in turn, states that in developing its Scoping Plan, the Air Resources Board will develop for each emission reduction measure "the range of projected greenhouse gas emissions reductions that result from the measure." This range

[52] Calpine Opening Comments at 12.
[53] AWEA Opening Comments at 11.
[54] Proposed Exhibit PG&E-7 (PGE 2018 ERRA…Update to Prepared Forecast) filed with the Commission in A.17-06-005 on November 2, 2017, p. 3 and Table 2-3.

> reflects the inherent uncertainty of forecasts, consumer response, and technological changes that can affect the range of expected reductions.
>
> Rather than follow SB32's legislative requirement that Scoping Plan measures be evaluated as a range of potential emission reductions, the Commission is attempting to go a step further and establish a fixed number. *A better approach, more consistent with SB32 and the Commission's jurisdiction, would be to ensure that LSEs meet the specific emission reduction measures identified in the Scoping Plan*.[55]

i. <u>The Commission Could Meet its IRP Goals by Ensuring Compliance with Existing Requirements</u>

Less than two weeks ago, on October 27th, CARB released its Draft Climate Scoping Plan identifying the "emission reduction measures" it planned to use to meet California's SB32 GHG reduction requirements. For the electric sector, the Scoping Plan proposes that;

- LSEs meet their 50% RPS requirement;
- California achieves the SB 350 goal of doubling energy efficiency; and
- California's Cap and Trade program continues its operation through 2030.[56]

All three of these programs are under Commission and/or CARB control and regulation, and, equally important, are consistently applied to all LSEs (IOUs, ESPs, and CCAs). All LSEs must meet the state's RPS requirements, the Commission has regulatory oversight of energy efficiency providers (either utility-run, CCA-run, or run by a third-party administrator); and the Commission's authority over IOU procurement influences its need for cap-and-trade allowances. All LSEs are also subject to the market forces and incentives that the cap-and-trade market has on energy prices and procurement choices.

As noted in CalCCA's Opening Comments, the Commission could focus its effort in the IRP to ensuring that the above emission reduction measures are implemented, without the need

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[55] CalCCA Opening Comments at 15 (*emphasis added*).

to develop an elaborate process of baseline resources, mass-based GHG benchmarks, and GHG planning prices, all of which (as discussed further below) are either unworkable or difficult to implement.[57] Such an approach also relies on the Commission's existing authority and does not raise any jurisdictional challenges.

These are in addition to the state's already established programs to ensure reliable electric service (another goal of the IRP process) which include:

- Resource Adequacy requirements;
- Renewable Integration Charge obligations (as noted in CalCCA's Opening Comments these resources can be self-procured by CCAs); and
- Electric storage requirements under AB2514.

All three of these programs also apply equally to all LSEs.

ii. CARB has already adopted a GHG Target for the Electric Sector Comparable to the 42 MMT Scenario Proposed by the Commission

In its recently approved Cap and Trade regulations, CARB has essentially defined the electric sector's expected contribution to meeting California's 2030 GHG reduction goals, and its results largely replicate the Commission's conclusions. CARB allocated California's three largest IOUs 49,549,521 allowances in 2021 declining to 46,453,091 allowances in 2030.[58] As each allowance is associated with one ton of GHG emissions this is equivalent to a 46.4 MMT GHG target for 2030, in line with the Commission's proposed 42 MMT. This will result in a

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[56] CARB Scoping Plan at 56-58.

[57] CalCCA Opening Comments at 15-16.

[58] Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, Section 95892 and Table 9-3a. As CARB states: "This workbook is a companion to the Second Notice of Public Availability of Modified Text and Availability of Additional Documents and/or Information to the California Cap on Greenhouse Gas Emissions

52% to 71% reduction in GHG emissions from 1990 levels from the electric sector, significantly above the minimum 40% reduction required under SB350.

CARB's forecast of allowances largely mirrors the same metrics proposed for use in setting a GHG-target and measuring compliance in the Reference System Plan. CARB's allocation to each utility is based on CEC forecasts of retail sales (which take into account energy efficiency and BTM activities), achievement of California's 50% RPS standard, and the planned or known retirement of power plants. Contrary to ORA's assertion (NC), the allowance allocation adjusts the allocation downward to reflect each utility's portfolio of other zero-GHG resources such as large hydroelectric and nuclear power.[59]

It is unclear if CARB's 2030 cap-and-trade target for the electric utilities includes the effect of SB350's doubling of energy efficiency (a program included in CARB's draft Scoping Plan but absent in the Reference System Plan). This estimate also does not include the feed-back look of the cap-and-trade program (discussed further below), as higher allowance prices increase the cost of fossil fuels and make additional renewable and zero-GHG resources (above the RPS requirement) more cost-effective.

Equally important, it does not include the additional GHG reductions from CCAs that voluntarily choose to exceed the mandatory RPS standards and/or seek to increase the proportion of zero-GHG resources in their portfolios.

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and Market-Based Compliance Mechanisms Regulation (Second Notice)." The workbook is available from CARB's website.

[59] CARB relies on each utility's S-2 submissions to the CEC as a starting point for this calculation. CARB has provided a workbook "as a companion to the Second Notice of Public Availability of Modified Text and Availability of Additional Documents and/or Information to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation (Second Notice)." The workbook is available from CARB's web-site and identifies the process CARB used to allocate allowances to the Electric Distribution Utilities. Forecasts of large hydroelectric and nuclear power usage for each utility were developed primarily based off of each utility's S-2 filings with the California Energy Commission.

Based on the above, it is reasonable to conclude that the Reference Plan's 42 million ton (MMT) planning goal for 2030 is a reasonable "stretch estimate" of what California's LSEs are likely to achieve *without the need* for the elaborate GHG planning effort proposed by the Commission.

iii. The Commission Needs To Clarify The Purpose Of The "Baseline" Resources Identified In The Reference System Plan

Under Energy's Division proposal, each LSE would have to develop one procurement plan based on the "Reference" portfolio, which includes existing "baseline" resources. Baseline resources are the existing *system-wide* mix of resources used to serve California load. In opening comments, Calpine interpreted the RS Plan as requiring that each LSE procure a mix of resources that match the system-average baseline mix of resources. To compound the problem, if a LSE went out and procured a mix of resources that matched the baseline, it could be exposed to accusations of "resource shuffling" to achieve GHG reductions from groups like TURN.

CalCCA opposes any attempt to require that CCA programs base their IRPs on a Commission-selected portfolio or any part thereof, including the baseline resource mix and incremental procurement above the baseline mix. As discussed in detail above and in CalCCA's opening comments, neither SB 350 nor any other statute requires that CCA programs base their IRPs or their actual procurement on the Commission's portfolio.

That said, CalCCA also has concerns regarding the "baseline" resources that extend beyond jurisdictional questions. Given the diversity of opinion as to what the baseline is and how it should be used, the Commission should clarify that the baseline is not a compliance requirement, and LSEs are not required to plan for or procure the baseline resource mix.

As noted by PG&E, Range, and others, no LSE would have a portfolio of existing resources that exactly matches the system-wide mix of resources. As CalCCA noted in its Opening Comments:

> It is important that the Commission recognize that each LSE is entering the IRP process with its own unique baseline portfolio. As discussed further below, this is one of the problems with the IRP process of trying to take a system-wide number and then assign it to individual LSEs. Few, if any, of the individual CCA portfolios are likely to include the same resource mix as the Commission's statewide baseline portfolio. Even the existing IOUs' baseline portfolios will not align with the system-wide portfolio.
>
> For instance, while the IRP baseline resources include some nuclear power, many CCA programs' portfolios do not and cannot include nuclear under policies adopted by certain CCA boards. Similarly, most of California's hydroelectric resources are already owned by existing IOUs and Publicly Owned Utilities ("POUs"). Thus, it is not possible to expect that each LSE meet the same starting baseline, and it cannot be required.[60]

Further confusing the issue, is that while the Reference Plan requires the use of a Reference Plan based on a *system-wide* resource mix, the mass-based GHG benchmark instead uses a different benchmark that is tied to each Electric Distribution Utility's ("EDU's") cap-and-trade allowance allocation.

Accordingly, the Commission should clarify that the baseline resource mix is for modeling purposes only, and is not a planning or procurement requirement for LSEs.

iv. The Proposed Mass-Based GHG Target is Not Workable for LSEs that only Provide Retail Energy Services

As noted in CalCCA's Opening Comments, a mass-based GHG emissions benchmark, while perhaps appropriate as benchmark for system-wide planning purposes, will not work if the Commission then tries to allocate this benchmark down to the individual LSE level. A mass-

[60] CalCCA Opening Comments at 14.

based GHG allocation to a CCA, for example, consists of three different inputs, only one of which is under direct CCA control.

The GHG emissions for any LSE will depend upon; 1) GHG reductions due to energy efficiency; 2) GHG reductions due to the actions of the customers themselves such as installing roof-top solar or participating in demand response programs; and finally, 3) the GHG-intensity of the energy delivered by the LSE. For almost all CCAs and ESPs (with the notable exception of MCE and Lancaster Clean Energy), it is the electric distribution utility that is responsible for energy efficiency, it is the individual actions of customers who are responsible for behind-the-meter and demand response activities (although LSEs can try and influence this behavior through incentives), and it is only the GHG-intensity of the delivered energy that is under control of the CCA or ESP.

In the base case used as input into the RESOLVE model for example,[61] over 50% of future expected GHG reductions will be met by customer-initiated and BTM activities. These activities constitute 45,699 GWh[62] out of expected retail needs in 2026 of 253,444.[63] This is more than the approximately 42,000 GWh that California's LSEs will need to procure during that same period to meet their 50% RPS standards by 2030.[64]

This weighting becomes even more pronounced in the RESOLVE model. The baseline assumption used in RESOLVE is that there will be an additional 16,593 GWh of BTM solar

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61 CEC 2016 IEPR Mid-range forecast.

62 This number would exceed 50,000 GWH if not for offsetting growth of around 5,000 GWh due to customers acquiring electric vehicles.

63 Attachment B (RESOLVE Documentation CPUC 2017 IRP), p. 12 using CEC 2016 IEPR mid-level forecasts.

64 This assumes California starts 2018 with 30% RPS, requiring LSEs to procure an additional 41,589 GWh (20% X retail sales of 207,748 GWh) to meet the 50% RPS standard.

photovoltaics.[65] This is almost 50% larger than the 10,100 GWh of utility-scale solar/wind resources proposed in the Reference Plan. When expected energy efficiency savings are added in, it is clear that perhaps 2/3[rd] or more of expected GHG reductions from the utility sector will be from activities that are beyond the control of a LSE that is just providing retail energy services.

It would be unreasonable to hold LSEs to meeting a Mass-based GHG target, ½ to 2/3rds of which is beyond their control. A better approach, as noted above, would be to focus on each of the GHG emission reduction measures identified by CARB in its Scoping Plan (RPS compliance, SB350 energy efficiency, and cap-and-trade compliance) and proportionally assign responsibility to the appropriate entity. Even this approach, as noted in CalCCA's opening comments, may unfairly disadvantage energy efficiency providers given that a significant portion of expected energy efficiency savings will come from non-LSE parties such as the CEC's building and appliance efficiency standards.

v. <u>The Proposed $150 GHG Planning Price Is Not Workable</u>

Putting aside the issue of the appropriate level of the GHG planning price (discussed below) the proposed GHG planning price presents several significant implementation problems.

As a threshold issue, use of the GHG Planning price confuses inputs with results. The basic concept of utility ratemaking is to identify how to achieve a goal (such as reducing GHG emissions) at minimal cost to ratepayers rather than establishing a blank check of spending up to some pre-determined level without any accounting for cost-effectiveness. While use of a GHG Planning price might work in a hypothetical system-wide resource planning model it is unclear

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[65] Attachment B (RESOLVE Documentation CPUC 2017 IRP), p. 12 using CEC 2016 IEPR mid-level forecasts. Even the CEC's low forecast predicts a 6,000 GWh increase of BTM solar PV (9,741 GWh to 15,627 GWh.)

how it is applied in the real-world. As noted in CalCCA's opening comments, the Reference Plan proposes to take the cost of the last ton of GHG reduction across the entire California electric grid, and then require each LSE to document (or justify why they didn't) spend up to this level. In the RESOLVE model, all resources (by type) are assigned the same cost. In real-life, the cost of resources will vary depending upon a number of factors such as a LSE's cost-of-financing, local conditions, use of union labor or any number of other factors. Requiring a LSE to document how it spent up to the $150 level treats a LSE that overpays for an inefficient, poorly managed plant the same as a LSE that efficiently met its GHG target at prices below the $150 level. This is comparable to a poorly designed energy efficiency program, where utilities receive incentives for the amount of money spent without any measurement of actual results. Since the planning price is based on the system-wide results of the RESOLVE model, it also fails to take into account the starting point of a LSE. The Energy Division's proposal does not distinguish between a LSE that is already starting out with a significantly low GHG level relative to a LSE that is starting out with high GHG emissions.

vi. Using The Actual Price Of Cap And Trade Allowances May Be A Better Approach For GHG Planning Purposes

One of the more controversial issues in this proceeding is setting the level of the GHG Planning price. The Reference Plan proposes to set a price for GHG emissions starting at $88/ton in 2018 and escalating to $150/ton in 2030. ORA, Calpine, PG&E, Edison, SDG&E and others all oppose the use of these values, instead believing that CARB's cap-and-trade prices should be used instead. The starting price set in the Reference Plan ($88/ton) is over six times the current cap-and-trade allowance price of $14 and the Reference Plan GHG price of $150 is over twice the highest price allowed by CARB of $66/ton under the cap-and-trade program.

The Reference Plan's proposed price is also higher than the "social cost" of GHG emissions used by CARB in its Scoping Plan which is set at $11/ton in 2015 rising to $16/ton in

2030 (at the same 5% discount rate assumed in the IRP) or from $56 to $73/ton at a lower 2.5% discount rate.[66] As CARB describes it:

> The social cost of carbon (SC-CO2) for a given year is an estimate, in dollars, of the present discounted value of the future damage caused by a 1-metric ton increase in carbon dioxide (CO2) emissions into the atmosphere in that year, or equivalently, the benefits of reducing CO2 emissions by the same amount in that year. The SC-CO2 is intended to provide a comprehensive measure of the net damages – that is, the monetized value of the net impacts – from global climate change that result from an additional ton of CO2.[67]

In setting its GHG Planning price, the Reference Plan is inconsistent with the proposed outcomes of CARB's proposed SB32 Scoping Plan. Much of this inconsistency may be explained by the Reference Plan being prepared prior to CARB's release, less than two weeks ago, of its latest proposed Scoping Plan.

The Reference Plan, for example, adopts its high GHG Planning price in part on the incorrect assumption that: "Cost-effective GHG reduction opportunities may not be available in other sectors, which could put overall state GHG reduction goals at risk." However, the Scoping Plan identifies a number of areas (including particularly transportation) that are below the proposed GHG Planning price.[68] Of note, this same table concludes that achievement of SB350's energy efficiency goals, which are not included in the Reference Plan, would provide cost-effective GHG reductions at a savings of $200 to $300 for each ton reduced. The Reference Plan also appears to undervalue the effectiveness of the cap-and-trade program, which applies to all sectors of the economy, in reducing GHG emissions.

The Reference Plan also appears to have a significantly different view of the effectiveness of the cap-and-trade program in reducing GHG emissions. As CARB describes it:

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66 CARB Scoping Plan, p. 60-61.
67 Id.
68 Id. at 69.

> The [cap-and-trade] program is up and running and has a five-year-long record of auctions and successful compliance. In the face of a growing economy, dry winters, and the closing of a nuclear plant, it is delivering GHG reductions. This is not to say that California should continue on this road simply because the Cap-and-Trade Program is already in place. The analyses in this chapter, and the economic analysis in Chapter Ill, clearly demonstrate that continuing the Cap-and-Trade Program through 2030 will provide the most secure, reliable, and feasible clean energy future for California—one that will continue to deliver crucial investments to improve the quality of life and the environment in disadvantaged communities.[69]

The Scoping Plan identifies cap-and-trade as providing the largest share of GHG reductions between 2021 and 2030 of 127 MMT. An advantage of the cap-and-trade program is that it provides incentives for all entities to develop the most cost-effective way to reduce GHG emission. Higher allowance prices, for example, should incent California's LSEs to move even further away from using fossil-fuels, as well as sending price signals to encourage the decarbonization of the transportation and other sectors of the economy.

If CARB believes it can reach its GHG reduction goals under the prices set by the cap and trade program, the Reference Plan in turn should set a price closer to the GHG allowance price.

E. The Commission Should Allow Banked RECs To Be Included Toward Achievement Of Any GHG Reduction Target

Excess banked RECs should count toward achieving any GHG reduction target set by the Commission. Such an approach is consistent with the operation of both the RPS program and the requirements of AB32 and SB32. Both AB32/SB32 recognize that "early action" to reduce GHG emissions should be recognized. Banked RPS procurement represents a GHG reduction from a previous year that has been carried forward for use in a later compliance period, while the

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[69] Id. at 40.

associated Renewable Energy Credit (REC) represents the environmental attributes, including GHG emissions, associated with the renewable generation.

The Commission recently reaffirmed the ability of LSEs to bank RECs for later use in D.17-06-026 consistent with the requirements of SBX1-2 and SB350.[70]

The multi-year treatment of RECs is almost identical to CARB's treatment of GHG allowances under its cap-and-trade program. Similar to the RPS program, cap-and-trade compliance is not measured in a single-year but instead over a multi-year compliance period. Similar to a banked REC, an allowance once issued remains good until it is retired. Thus an allowance issued in 2012 (the first year of the program) could be retained and used for compliance up through 2030.

The reasoning for this multi-year treatment is consistent with CARB's policy of focusing on cumulative GHG emissions rather than just hitting an emissions target in a similar year. This is particularly important given the long residence time of GHG pollutants in the atmosphere. As CARB explains in its just released Scoping Plan:

> Further, once GHGs are emitted into the atmosphere, they can have long lifetimes that contribute to global warming for decades. Policies that reduce both cumulative GHG emissions and achieve the single-year 2030 target provide the most effective path to reducing climate change impacts. A cumulative construct provides a more complete way to evaluate the effectiveness of any measure over time, instead of just considering a snapshot for a single year.[71]

CARB also notes:

> [T]hat in any year, GHG emissions may be higher or lower than the straight line. That is to be expected as periods of economic recession or increased economic

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[70] As D.17-06-026 states: SB 2 (1X) introduced both the use of procurement content categories for RECs and a new system of counting RECs that could be used as excess procurement to be applied in later compliance periods. The calculations for excess procurement rely on a combination of the PCC classification of the RECs and whether the RECs are associated with short-term or long-term contracts" citing in turn to "SB 2 (1X) at Section 399.13(a)(4)(B); D.12-06-038 at Section 3.7 and OPs 27-32

[71] CARB Scoping Plan at 39.

> activity, annual variations in hydropower, and many other factors may influence a single or several years of GHG emissions in the State.[72]

Opponents of counting banked RECs focus solely on the issue that doing so is either "a barrier" (NRG) or has the effect of "suppressing" (AEE) new renewable development. Such an approach is not only self-serving but also short-sighted. New renewable developers should have the certainty that if renewable energy from their project (and the associated REC) is not needed in a given year, it will still be available for later use. This certainty increases the value of any new project.

Finally, both the CAISO and NC misinterpret the 36-month retirement period for RECs. While a REC must be retired within 36 months of generation, once retired it can be found surplus, as discussed above in D.17-06-026, to a LSE's needs and thus carried forward for use in subsequent compliance periods long-after the 36-month retirement period. Thus, as CAISO notes, the RESOLVE model can use banked RECs from 2022 in 2030 results and be in full compliance with California's RPS requirements.

F. CalCCA Conditionally Supports Increased RPS

As noted in its opening comments, CalCCA supports the State's efforts to increase renewable resource procurement through the RPS program. Existing CCA programs are already on pace to significantly exceed both the Commission's renewables procurement requirements and their share of the State's GHG-reduction goals and are making this progress without any external prodding or regulation by the Commission.

In their opening comments, some parties, including ACC and CalWEA, supported increasing the RPS to 60% by 2030, which corresponds to SB100's proposed requirement, while other parties supported a 58% RPS requirement which appears to be the level necessary

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72 CARB Scoping Plan at 34.

to achieve the 42 MMT GHG target proposed by the Commission.[73] (Although Edison notes that CARB staff appear to state that only a 50% RPS is needed to achieve the 42 MMT level.) PG&E proposes a 54% RPS, which appears to reflect the combined effect of meeting the current 50% requirement plus the effect of cap-and trade allowance prices on spurring additional RPS procurement. A number of parties oppose any increase above the current 50% level.[74]

As stated in CalCCA's opening comments, CalCCA does not oppose increased RPS if the increase is done in a fair and reasonable manner. However, the Commission should not use RPS as an end-run around SB 350's protections for CCA procurement and planning autonomy. In particular, the Commission should not attempt to use RPS increases to spur CCAs into planning for or procuring the resource mix or procurement timing identified by the Commission in its portfolio.

G. CalCCA Opposes Additional Non-RPS Renewables Procurement

Several parties, including CEJA/SC and CESA, support authorizing additional renewables procurement outside of RPS. On the other side, PG&E has expressed the concern that siloed procurement would invite jurisdictional challenges from CCAs and exacerbate cost allocation issues.

PG&E's concerns are well justified, as the Commission does not have the authority to impose any renewables procurement requirement on CCA programs outside of the RPS program. In addition, the Commission does not have the authority to require that existing CCA programs

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73 Although ORA takes no position in this proceeding on raising the RPS, it states that a 58% RPS requirement is consistent with the 42 MMT goal. AWEA proposes a 58% RPS while IEP, CEERT, and Defenders of Wildlife support a RPS that achieves the 42 MMT goal

74 AReM, CLECA, CMUA, Imperial County, NRDC, POC, and SDG&E. EDF supports raising the level but did not provide a number, while UCS would retain the 50% RPS but put LSEs on notice if they didn't exceed the 50% requirement if beneficial to do so.

pay NBCs for IOU renewables procurement authorized outside of RPS, including procurement authorized through other programs, like the Renewables Auction Mechanism ("RAM") program.

If the Commission does move forward with non-RPS renewables procurement, it must do so in a manner that preserves CCA autonomy as required by SB 350. At a minimum, any non-RPS procurement should meet the following conditions: 1) the procurement requirement applies only to IOUs and is strictly optional for CCAs; 2) the Commission protects local choice and prevents stranded costs by ensuring that the IOUs do not engage in PCIA-eligible procurement on behalf of reasonably projected departing load; 3) the procurement does not otherwise reduce or interfere with CCA procurement autonomy; and 4) the procurement is explicitly recognized as ineligible for NBC recovery from existing or projected CCA programs.

H. CCA Programs Are Not "Gaming The System"

In its opening comments, TURN opposes the proposed GHG planning price metric, in part, on the grounds that "TURN believes that many LSEs will rely on creative accounting and resource shuffling to procure extensively form existing operating resources, including those located outside of California, rather than procuring the newly developed resources suggested by the RESOLVE model."[75] In identifying the specific accounting and shuffling strategies that it is concerned about, TURN pays special attention to CCA programs, stating that:

- "Many LSEs (particularly CCAs and ESPs) treat purchases of unbundled Renewable Energy Credits from existing facilities across the Western grid as GHG offsets when matched with the purchase of unspecified system power."[76]
- "Many LSEs (particularly CCAs) treat purchases of 'firmed and shaped' renewable energy from out-of-state intermittent generators as zero GHG procurement."[77]

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75 TURN Opening Comments at 12.
76 TURN Opening Comments at 14-15.
77 TURN Opening Comments at 15.

- "CCAs purchase large volumes of out-of-state legacy hydroelectric generation to justify their claims that their overall supply portfolio has lower GHG emissions than the incumbent investor-owned utilities."[78]

As a threshold matter, nothing in SB 350 requires that CCA programs meet their SB 350 goals through the procurement of new resources, whether a CCA program chooses to meet SB 350's goals through the purchase of newly developed resources or existing resources is not a Commission-jurisdictional question. That said, there are strong reasons to believe that CCA programs, without any external prompting from the Commission, will develop into major drivers of new renewable resource development. In criticizing CCA programs, TURN fails to account for the market impact of CCA programs' internal GHG reduction and renewables procurement goals.

CCAs are dedicated to achieving and exceeding the State's environmental goals. At the same time, new CCA programs are faced with the unique challenge of building a new organization from the ground up and procuring a portfolio that meets internally imposed environmental requirements that are often significantly more ambitious than the mandatory requirements that the IOUs comply with. New CCA programs have to build credit, recruit a procurement staff, and establish relationships with developers and suppliers, while at the same time competing with IOUs that enjoy a massive market power advantage over them. The fact that some CCAs have initially relied on RECs, firmed and shaped imports, and out of state hydro to meet their environmental goals is simply a reflection of the challenges faced by new CCA programs, not evidence of any intent to "game the system." More established CCA programs have significantly diversified their portfolios, transitioning away from these measures. For example, PCE procured 300 MW of new solar projects during its first year of operation.

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78 TURN Opening Comments at 16.

However, even if CCAs continue to utilize these products to meet their goals, this decision is solely within the purview of their governing boards, not TURN and not the Commission, as these products are specifically authorized for such purposes under current law. CCAs are delivering value to their customers while procuring resources at renewable energy content levels that are often decades ahead of state mandates.

III. CONCLUSION

CalCCA thanks the Commission for taking the time to consider these reply comments. CalCCA and its member CCA programs look forward to working closely with the Commission to ensure that SB 350's goals are met.

Dated: November 9, 2017

Respectfully submitted,

/s/ David Peffer

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For the
California Community Choice Association

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements	Rulemaking 16-02-007 (Filed February 11, 2016)

MARIN CLEAN ENERGY
THREE-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

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November 17, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements	))))))	Rulemaking 16-02-007 (Filed February 11, 2016)

MARIN CLEAN ENERGY
THREE-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission's Rules of Practice and Procedure and Public Utilities Code Section 1701.3(h)(2), Marin Clean Energy ("MCE") hereby gives advanced notice of a meeting with Jason Houck, advisor to Commissioner Randolph. The meeting is scheduled on November 20, 2017 at 1:00 pm. CC Song, MCE Senior Policy Analyst, and Hilary Staver, Silicon Valley Clean Energy Regulatory and Legislative Analyst will be in attendance.

Respectfully submitted,

/s/ Troy Nordquist

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November 17, 2017

November 21, 2017

Timothy J. Sullivan
Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Subject: Withdrawal of Ex-Parte Notice of Marin Clean Energy in R. 16-02-007

Dear Mr. Sullivan:

MCE hearby withdraws its ex-parte notice in proceeding R. 16-02-007, filed on November 17, 2017. As R. 16-02-007 is a quasi-legislative proceeding, ex-parte notices are not required.

Sincerely,

/s/ Troy Nordquist

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements	Rulemaking 16-02-007 (Filed February 11, 2016)

OPENING COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
ON THE PROPOSED DECISION

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January 17, 2018

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In accordance with Rule 14.3 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the California Community Choice Association ("CalCCA") respectfully submits the following comments on the December 28, 2017 *Proposed Decision of Commissioner Randolph Setting Requirements for Load Serving Entities Filing Integrated Resource Plans* ("Proposed Decision").

I. INTRODUCTION AND SUMMARY

CalCCA and Community Choice Aggregation ("CCA") programs, individually and jointly, have actively participated in this proceeding. CalCCA appreciates the significant efforts of Commission staff in developing the underlying plans and proposals supporting the Proposed Decision. CalCCA and its members wholeheartedly share the Commission's dedication to achieving California's greenhouse gas ("GHG") emissions reduction goals, as well as California's other environmental and system-reliability goals. The Commission can be assured that CCA programs will work collaboratively and cooperatively in fulfilling requirements associated with Integrated Resource Plans ("IRP").

CalCCA is very concerned, however, with the tone and characterizations set forth in the Proposed Decision. As written, the Proposed Decision greatly misconstrues fundamental positions advanced by CalCCA, and in doing so makes conclusions and proposes outcomes that are more rigid, strident and extensive than necessary. The Proposed Decision characterizes CalCCA as objecting to "any" form of authority by the Commission, and states that CalCCA believes the Commission only has "rubber stamp" authority over CCA IRPs.[1] These characterizations are incorrect, and obscure reasonable outcomes that align with the concurrent jurisdictions and shared responsibilities. To be clear, CalCCA has not advocated for a "hands off" approach, but rather for an approach that recognizes and accommodates meaningful differences, and that applies principles of cooperation.

As CalCCA has stated repeatedly, CalCCA appreciates the important work given to the Commission with respect to IRP matters. The importance of the work and the appeal of central planning, however, do not demand or justify a one-size-fits-all outcome. As a legal matter, certain lines of demarcation and distinction must be acknowledged, and deference accorded to local governing boards as the Commission works to weave CCA programs into the overall fabric of the important IRP process. In this key and principal regard, the Proposed Decision errs by not harmonizing (or even acknowledging) statutory principles and directives supporting local CCA planning and procurement responsibilities. The Proposed Decision can and should be revised to reflect the concurrent jurisdiction and shared responsibilities. This can be accomplished without forsaking the important role the Commission plays with regard to CCA programs' IRPs. Contrary to the Proposed Decision's mischaracterizations, this is *not* an "either/or" proposition, but a "both/and" one.

II. COMMENTS

A. CalCCA Supports Key Aspects Of The Proposed Decision

CalCCA recognizes the significance of the Commission's task in establishing the IRP process, and appreciates the Commission's hard work in the IRP proceeding. CalCCA supports

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1 *See* Proposed Decision at 20-21.

key aspects of the Proposed Decision. For example, CalCCA agrees with the Proposed Decision's conclusion that there is no need to order near-term procurement.[2] As recognized by the Proposed Decision, the cost savings from tax credits are highly uncertain, and there is no general need for additional renewable resource procurement until 2026.[3] Further, CalCCA is encouraged by the Proposed Decision's recognition of the problematic nature of investor-owned utility ("IOU") procurement on behalf of departing load customers.[4] CalCCA strongly believes CCA programs should be allowed to select their own resources to the maximum extent possible, and should not be burdened by IOU procurement on their customers' behalf.

CalCCA also views several elements of the Proposed Decision's treatment of GHG targets as steps in the right direction.[5] As a general matter, CalCCA supports allowing load-serving entities ("LSE") the flexibility to choose between using a GHG benchmark or a GHG planning price in developing their individual IRPs.[6] However, a number of implementation issues need to be resolved. For instance, CalCCA is concerned that under the proposal, compliance will be judged based on the GHG planning price regardless of whether the benchmark or the planning price is used. CalCCA also believes that efficiency would be best-served if the CPUC revised the LSE-Specific GHG Emissions Benchmark Table to express the benchmarks in million metric tons ("MMT") CO2e / MWh, as opposed to MMT. In other words, the Commission should use an emissions intensity benchmark, not an emissions benchmark. CalCCA also supports the Proposed Decision's downward revision of the GHG planning price in the early years of IRP to better align with actual California Air Resources

[2] Proposed Decision at 81-83, 122-123 (Finding of Fact 10), 126 (Conclusion of Law 20).

[3] Proposed Decision at 82.

[4] Proposed Decision at 82-83.

[5] All further statutory references are to the Public Utilities Code, unless otherwise noted.

[6] Proposed Decision at 95, 123 (Finding of Fact 13), 127 (Conclusion of Law 23).

Board ("CARB") cap-and-trade prices.[7] In addition, CalCCA supports the Proposed Decision's preservation of LSEs' ability to use banked RPS procurement.[8] However, as discussed below, CalCCA has concerns regarding the Proposed Decision's treatment of Portfolio Content Category ("PCC")-2 renewable energy credits ("REC").

Finally, CalCCA supports using the upcoming IRP cycle as a test year. CalCCA looks forward to working with the Commission and stakeholders to refine the IRP process, and develop an appropriate way for the Commission to certify CCA IRPs in concert with local authority. In this regard, CalCCA asks the Commission to expressly state that the test year will be used to refine the IRP process so that it more accurately reflects principles of cooperation between the Commission and local CCA governing boards on various matters of concurrent jurisdiction and shared responsibilities.

B. The Proposed Decision Errs With Respect to Characterizing And Applying Concurrent Jurisdiction Principles

CalCCA shares the Commission's dedication to achieving California's GHG reduction and renewable energy goals. However, CalCCA believes that these goals must be achieved in a manner that is consistent with statute and respects the principle of CCA planning and procurement autonomy. CalCCA believes the Proposed Decision, as currently written, includes errors of law that unnecessarily obscure reasonable ways of accommodating and implementing concurrent jurisdictions. As noted above, this is not an either/or proposition, but a both/and one.

As a threshold matter, CalCCA urges the Commission to consider principles of comity and cooperation when interpreting its IRP jurisdiction over CCAs.[9] CalCCA recognizes that the

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7 Proposed Decision at 95-96.

8 Proposed Decision at 34.

9 As highlighted above, while CalCCA has taken strong positions on certain jurisdictional positions, the Proposed Decision errs in finding that the sum and substance of CalCCA's arguments advocate for "rubber stamp" authority by the Commission. (*See* Proposed Decision at

Commission may be concerned about its ability to fulfill its duties with respect to GHG reduction goals. It appears that these concerns may be causing the Commission to assert jurisdictional statements that, while helpful for ensuring central planning and control, are at odds with the IRP statute and principles of comity and cooperation.

CalCCA requests that the Proposed Decision be revised to remove erroneous and unnecessary statements about the Commission's jurisdiction. Concurrent jurisdiction is involved, and CCA programs have repeatedly stated that they will fully cooperate with the Commission to *jointly* achieve GHG reduction goals in a positive, collaborative manner. This approach is consistent with principles of comity and cooperation – principles that are attendant in situations involving concurrent jurisdiction and shared responsibilities between public agencies. As such, the Proposed Decision should be revised to reflect these principles. Moreover, the Commission should use the test year to tease out and refine how these principles apply to specific CCA IRP submittals.

As required by Rule 14.3(c), CalCCA specifically addresses below certain legal errors in the current version of the Proposed Decision. In doing so, it is not CalCCA's intent to reargue or restate past arguments, and these comments are necessarily summary in nature. These legal errors flow from a common problem: a failure by the Commission to acknowleldge and accommodate the general jurisdiction that the Legislature has given CCA governing boards by the Legislature. Issues relating to how this general jurisdiction intersects with the Commission's jurisdiction are understandable, and should be addressed. But, the Proposed Decision's failure to properly recognize the general jurisdiction of local CCA governing boards and the failure to accommodate this general jurisdiction constitute legal error.

22.) The tone of these and other statements in the Proposed Decision are unfortunate, and do not reflect CalCCA's views regarding the Commission's important role with respect to CCA IRPs.

As a preliminary matter, CCA programs are not subject to the Commission's general jurisdiction. This statement is not intended to be dogmatic or inflammatory, but foundational insofar as it helps to support a proper understanding of how the concurrent jurisdictions are intended to coexist. The Commission has expressly stated that its jurisdiction over CCA programs is circumscribed and limited, attaching only to express statutory mandates applicable to CCA programs and to matters that would necessarily compromise or impact the IOU's service or rates to bundled customers.[10] With regard to CCA energy procurement activities, this principle is explicitly stated in Section 366.2(a)(5), which provides that: "a community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers except where other generation procurement arrangements are expressly authorized by statute." Under this statute, each CCA program has full authority over its own procurement and procurement "activities" (including procurement planning) except where the Commission has been *expressly* granted jurisdiction over CCA procurement activities by statute.

These statutory foundations help interpret Sections 454.51 and 454.52. The Proposed Decision claims that the Commission's authority over CCA IRPs is, as a practical matter, the same as the Commission's broad authority to appove, deny, or modify IOU IRPs. In effect, the Proposed Decision states that there should not be any difference between IOU and CCA IRPs. The Proposed Decision also asserts that Section 454.52(b)(3) merely adds CCA board approval as an *additional* step to the IRP process, a step that does not "subjugate the Commission's

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[10] *See, e.g.,* D.05-12-041 at 8-12. *See also Los Angeles Met. Transit Authority v. Public Utilities Com,* (1959). 52 Cal. 2d 655, 661 ("[I]n the absence of legislation otherwise providing, the PUC's jurisdiction to regulate public utilities extends only to the regulation of privately owned utilities.").

authority to that of the CCA governing boards."[11] Moreover, the Proposed Decision goes further by stating, with respect to CCA IRPs, that "it is well within the authority of the Commission to require IRP filings, in *any manner* it determines…."[12] As set forth briefly below, CalCCA provides two responses: (1) these conclusions are erroneous and inconsistent with SB 350's basic structure and plain language and (2) even if these conclusions were legally sustainable, the conclusions are incompatible with principles of comity and cooperation as to matters of concurrent jurisdiction. Taken together, CalCCA urges the Commission to remove these overbroad statements, and, more importantly, to modify the Proposed Decision so that it accommodates meaningful differences and distinctions among jurisdictional LSEs.

As to the first response, CalCCA will not restate or reargue past legal positions.[13] The Proposed Decision's position is contradicted by the plain language of Section 454.52(b)(3). In this section, the Legislature vested the authority to approve a CCA program's IRP in that CCA program's governing board, and uniquely defined the Commission's role as *certifying* CCA IRPs. The Proposed Decision does not sufficiently analyze this distinction. Had the Legislature intended to give the Commission the authority to approve, deny, or modify a CCA program's IRP, or if the Legislature had intended (as the Proposed Decision claims) a two-step process in which both the Commission and CCA boards have the authority to approve, deny, or modify a CCA program's IRP, it would have clearly stated as such. The Legislature could have easily included language explicitly requiring that CCA programs "file" their IRPs with the Commission "for approval." Instead, the Legislature used two different terms to define the roles of the Commission and the CCA boards – clearly signaling that the Legislature did not intend the

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11 Proposed Decision at 22.

12 Proposed Decision at 24 (emphasis added).

Commission to have the same authority to approve or deny a CCA programs' IRP.[14] The same applies to the terms "certification" and "approval." The Legislature was certainly aware of the term of art "certify" when it decided to define the Commission's role.[15] In addition, the Proposed Decision's assertion that the Commission's certification authority is substantive in nature is incompatable with the plain language of Section 454.52(b)(3), which vests the substantive authority to approve a CCA's IRP in that CCA programs' board. The Proposed Decision's failure to give these distinctions sufficient weight, analysis or relevance is legal error. It is a fundamental principle of statutory interpretation that, in interptreting apparently conflicting statutory provisions, specific exceptions are controlling over general rules.[16] The Section 454.52(a)(1) language authorizing the Commission to adopt requirements to "ensure that load-serving entities" meet the eight Section 454.52(a)(1)(A-H) criteria is inconsistent with Section 454.52(b)(3), which makes clear that CCA programs' governing boards have authority to approve their programs IRPs based, in part, on whether the IRPs "achieve results consistent

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13 CalCCA provided a detailed legal analysis of the Commission's authority over CCA programs' IRPs in its October 26, 2017 Comments on the Proposed Reference System Plan (at 4-10). These arguments are incorporated herein by reference.

14 *See California Teachers Assn. v. Governing Bd. of Rialto Unified Sch. Dist.* (1997) 14 Cal. 4th 627, 633 (courts have no power to rewrite a statute so as to make it conform to a presumed intention which is not expressed by the legislature). *See also Jones v. Lodge at Torrey Pines P'ship* (2008) 42 Cal. 4th 1158, 1166 ("We believe that if the Legislature intended to place all supervisory employees in California in such a conflict of interest, the Legislature would have done so by language much clearer than that used here"); *Moore v. California State Bd. of Accountancy* (1992) 2 Cal. 4th 999, 1031 ("Had the Legislature meant to prohibit use of the unmodified term 'accountant,' it simply would have said so").

15 *See Ste. Marie v. Riverside County Regional Park & Open-Space Dist. (2009) 46 Cal.4th 282, 288-289; People v. Dillon (1983) 34 Cal.3d 441, 468* (when the same word appears in different places within a statutory scheme, courts generally presume the Legislature intended the word to have the same meaning each time it is used). CalCCA provided background and analysis on the meaning of "certification" in the context of Commission regulation of CCA programs in its October 26, 2017 Comments on the Proposed Reference System Plan (at 6).

16 *Sterling Park, L.P. v. City of Palo Alto* (2013) 57 Cal. 4th 1193, 1199–1200. *See also Hopkins v. Superior Court* (2016) 2 Cal. App. 5th 1275, 1283.

with" the eight criteria. In light of this conflict, Section 454.52(a)(1) *must* be interpreted as a general rule, modified, in the case of CCA programs, by the CCA-specific exception established in Section 454.52(b)(3).

On a related matter, the Proposed Decision appears to unnecessarily and erroneously extend the Commission's short-term Resource Adequacy ("RA") planning authority to long-term procurement planning. The RA statute (Section 380), which gives the Commission authority with respect to reliability and RA matters, is not independent of statutory authority pertaining to CCA programs. The various statutory provisions must be read in harmony; this is where the Proposed Decision appears to repeatedly go astray. Section 380(b)(5) requires that the Commision's RA program "maximize the ability of community choice aggregators to determine the generation resources used to serve their customers." Similarly, Section 380(h)(5) requires that the Commission "ensur[e] that community choice aggregators can determine the generation resources used to serve their customers." In light of these provisions, which clearly require that the Commission use its RA authority to preserve and respect CCA procurement autonomy, the RA statute cannot reasonably be interpreted as giving the Commission the kind of central planning authority over CCA programs envisioned by the Proposed Decision.

As to the second response, even if the Proposed Decision's legal conclusions were correct, they are incompatible with priniciples of comity and cooperation as to matters of concurrent jurisdiction. To be clear, SB 350 vests in CCA local governing boards key jurisdiction with respect to CCA IRPs. The Proposed Decision gives fleeting legal significance to this undeniable point. More importantly, the Proposed Decision fails, as a practical matter, to accommodate this point. The absence of reasonable, practical accommodations stands in contrast to the Proposed Decision's willingness to accommodate special provisions for other LSEs. For example, the Proposed Decision would provide special accommodations for

PacifCorp.[17] While noting that CalCCA had proposed "a separate process for CCAs, designed to accomplish 'certification'",[18] the Proposed Decision fails to discuss or accommodate this proposal. There is no reasonable basis for denying this proposal, particularly since the first year is a test year and can be used to refine and shape the nature and fluidity of the IRP process. More importantly, accommodating this proposal would give practical effect to legal principles of comity and cooperation. Therefore, CalCCA urges the Commission to modify the Proposed Decision to expressly describe how the test year will be used to refine the IRP process to employ principles of cooperation vis-à-vis local CCA governing boards.

C. The Commission Can Use Its Existing Authority To Achieve IRP Goals

In its Opening Comments on the Staff Proposal, CalCCA noted that the Commission has the authority to set – and increase – RPS requirements, and explicitly endorsed increasing LSEs' RPS targets in order to achieve the Energy Division's stated IRP GHG reduction goals.[19] Similarly, as noted above, the Commission's existing RA authority is more than adequate to ensure reliability while concurrently respecting CCA programs' right to procure generation. These other programs could intersect with the IRP program, and provide practical means by which the Commission could enforce IRP goals without needing to implement rigid IRP requirements on CCA programs. Specifically, if, through its review process, the Commission identifies long-term reliability issues associated with a CCA program's IRP, it will have ample opportunity to work with that CCA program to remedy those issues, and CCA programs will have a significant incentive to address any shortfalls through the IRP process rather than waiting for shortfalls to become Commission-jurisdictional RA problems.

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17 *See, e.g.,* Proposed Decision at 106 (describing the fact that PacifiCorp can, notwithstanding the filing requirements of other LSEs, simply file what PacifiCorp files in other jurisdictions, supplemented by certain information on disadvantaged communities).

18 *See* Proposed Decision at 105.

D. The Commission Should Not Adopt The Clean Net Short Proposal Without A Formal Evaluation Process

The Proposed Decision, with very little discussion, would adopt Pacific Gas and Electric Company's ("PG&E") Clean Net Short ("CNS") proposal for calculating GHG emissions.[20] This proposal would calculate a LSE's GHG emissions on an hourly, rather than an annual, basis. Adoption of this proposal is premature as it is: (1) inconsistent with the direction of the Governor, (2) would pre-judge the outcome of the California Energy Commission's ("CEC") Assembly Bill ("AB") 1110 rulemaking process (16-OIR-05), (3) unfairly penalizes LSEs that have already made significant investment in GHG reductions, (4) is inconsistent with the annual reporting requirements of the CARB and CEC, and (5) is inconsistent with the statutory requirements of the RPS legislation as implemented by the Commission. For these reasons, CalCCA requests that the CNS proposal be removed from the Proposed Decision.

AB 79, passed last year by the Legislature, would have directed the CARB to examine the feasibility of calculating GHG emissions for the electric sector on an hourly basis. On October 3, 2017, Governor Brown vetoed AB 79. In vetoing AB 79, Governor Brown directed that the calculation of GHG emissions should be done under existing law (AB 1110), which directs the CEC to develop a consistent GHG-reporting regime. To date, over twenty parties, including PG&E, have submitted comments in the CEC's process. The vast majority of these parties support an annual calculation of GHG emissions and not PG&E's hourly CNS proposal. Even the CEC staff's own initial proposal in the AB 1110 pre-rulemaking process proposes the continued use of CARB's default emission factor and use of annual, not hourly, calculations.[21]

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19 *See* CalCCA Comments on the Proposed Reference System Plan at 31-32.

20 Proposed Decision at 97-98, 123 (Finding of Fact 17), 127 (Conclusion of Law 25).

21 *See* Draft Staff Paper at 9 (proposing calculation of GHG emissions on an annual basis) and 16 (proposing that "CARB's default emissions factor would be used for all sources of unspecified power.").

The Commission should not "tip the scales" and pre-judge the outcome of the CEC's statutorily required AB 1110 rulemaking process.

In addition to being procedurally premature, adopting PG&E's CNS proposal is also unfair and would penalize LSEs that provide GHG-free energy to California's electric grid. Key facts remain in dispute as to whether or not PG&E's CNS proposal would unfairly penalize 100% GHG-free/RPS PCC-1 solar resources. This is so because, under PG&E's CNS proposal, the LSE could only claim a fraction of the solar generation that perfectly matched its load profile. Thus, the LSE would receive no GHG reduction credit for generation that did not match its load profile. Under PG&E's CNS proposal, it is unclear that any LSE could claim to be 100% GHG-free unless it was able to exactly match zero-GHG generation to its load during all hours of the year. This result is untenable. It unfairly penalizes LSEs that have made significant investments in renewable and zero-GHG energy by not giving them credit for all of their generation, and in turn assigning the GHG benefit to other LSEs that made no durable financial commitments to sustain zero-GHG energy production.

PG&E's CNS methodology is also at odds with the Proposed Decision's reliance on CARB's GHG emissions calculation. As the Proposed Decision recognizes, under SB350, it is CARB, and not the Commission, that sets the GHG emissions target for the electric sector and the individual LSEs comprising that sector. CARB's allocation methodology is based on <u>annual</u> GHG emissions for each entity, not hourly. A significant mismatch will occur between the LSE-specific GHG targets to be set in the IRP process and the methodology used to determine compliance if the Commission adopts PG&E's CNS proposal. This is particularly troubling since, as discussed above, PG&E's CNS proposal penalizes LSEs that have high amounts of zero-GHG resources while rewarding LSEs that rely extensively on unspecified system-wide power. Thus, paradoxically, those LSEs that have already reduced their GHG emissions will have a harder time meeting their IRP goals.

PG&E's CNS proposal has other flaws and problems. The proposal is inconsistent with the Power Source Disclosure/Power Content Label requirements. PG&E's CNS proposal cannot be adopted unless the Commission can harmonize or otherwise legally justify these differences. PG&E's CNS proposal also appears at odds with the RPS program. PG&E's CNS proposal would adopt significant new restrictions on the ability of zero-GHG RPS-eligible resources (including PCC-1 resources) to be credited toward a LSE's GHG emissions target. Under the Portfolio Content Category rules, the PCC-1 designation of a RPS resource is based on where and how the energy was generated, not if it was used to serve load. An LSE can purchase PCC-1 RPS-eligible wind or solar energy, retain the associated REC while reselling the underlying energy to another entity and the REC still retains its PCC-1 (and zero-GHG) status. Under PG&E's proposal, this PCC-1 REC would not be allowed to count as a zero-GHG resource, thus creating a significant mismatch between RPS and GHG reporting. Finally, the Proposed Decision provides little or no guidance, beyond a simple illustrative example provided by PG&E, regarding how to implement PG&E's CNS proposal. In less than four months (assuming a February decision), the Proposed Decision contemplates a process by which the zero-GHG eligibility of resources would be determined, emission profiles for non-zero GHG resources developed, an 8,760 hour system-wide emission profile produced, and the results of this analysis provided to all LSEs in time for them to incorporate this methodology into their own IRPs, currently due on June 1, 2018. This is problematic, to say the least.

For these reasons, CalCCA requests that the Commission withdraw the CNS proposal from the final decision, and adopt the final regulations of AB 1110 once those are finalized at the CEC. This approach would respect the authorities set forth in AB 1110. In this regard, it is CalCCA's understanding that, earlier today, the CEC issued a draft staff paper in 16-OIR-05 with respect to a *Revised Assembly Bill 1110 Implementation Proposal For Power Source Disclosure.*

E. The Proposed Decision's Treatment of PCC-2 RECs Should Be Revised

The Proposed Decision would adopt the "Standard LSE Plan" included in Attachment A to the Proposed Decision. Attachment A provides instructions on how LSEs are supposed to prepare their IRPs. As generally described above, Attachment A (as currently written) would require that LSEs account for their GHG emissions using the CNS methodology, which would define PCC-1 RECs as GHG-*free* resources and PCC-2 RECs as GHG-*emitting* resources.[22] In addition to the reasons stated above, use of the CNS in this way is problematic for two additional reasons. First, the decision to treat PCC-2 RECs as GHG-*emitting* resources is not supported by findings of fact, conclusions of law, or ordering paragraphs from the actual decision. Second, the decision to treat PCC 2 RECs as GHG-*emitting* resources is inconsistent with the RPS program, which gives full credit for PCC 2 RECs. Like PCC 1 RECs, PCC 2 RECs represent actual renewable generation with actual GHG reductions. CalCCA requests that the Commission revise Attachment A to include PCC-1 RECs and PCC-2 RECs as GHG-free resources.

III. CONCLUSION

CalCCA thanks the Commission for its consideration of these comments.

Dated: January 17, 2018 Respectfully submitted,

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22 Proposed Decision Attachment A at 6.

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January 22, 2018

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I. SUMMARY

As expected, numerous parties filed opening comments on the Proposed Decision. This is a reflection of the significant work embodied in the Proposed Decision and its relevance to California's ambitious greenhouse gas ("GHG") reduction goals. As CalCCA stated in its opening comments, it is appropriate in light of statutory directives and principles for the Commission to accord deference to local governing boards of Community Choice Aggregation ("CCA") programs, which are working concurrently to achieve these same goals. Based on presumably competitive and parochial interests, however, certain parties support rigid, uniform applications of Integrated Resource Plan ("IRP") requirements to all Load-Serving Entities ("LSEs"). CalCCA urges the Commission to reject these biased arguments, and adopt a balanced outcome for CCA programs that provides necessary Commission oversight while respecting local prerogatives. CalCCA looks forward to working with the Commission to develop, refine and implement this cooperative approach.

II. COMMENTS

A. Jurisdiction

Several parties submitted opening comments asserting unfettered Commission jurisdiction over CCA IRPs. As noted in CalCCA's opening comments, these comments are based on flawed and incorrect interpretations of Public Utilities Code Sections 454.51 and 454.51, and as such commit errors of law.[1] These arguments assume exclusive Commission jurisdiction, and in doing so fail to recognize the principles of concurrent jurisdiction, including cooperation and comity.[2]

Two specific claims merit closer attention. First, California Unions for Reliable Energy ("CURE") claims that the Commission's legislative mandate to identify a "diverse and balanced portfolio of resources" must, notwithstanding any express language or reasonable inference, mean that uniform control is needed over CCA programs, since according to CURE "there is no reason that the Legislature would have given the Commission this enormous task and required CCAs to submit IRPs to the Commission if the Legislature did not intend the Commission to implement that portfolio." (CURE Comments at 5.) In addition to being unsupported, this argument is contradicted by Section 454.51(b), which expressly requires that investor-owned utilities ("IOUs"), but not CCA programs, base their portfolios on the Commission's "diverse and balanced portfolio." This is only one of various ways in which the Legislature distinguished CCA IRPs from IOU IRPs. (*See, e.g.,* CalCCA Comments at 4-10.) In doing so, the Legislature

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1 *See, e.g.,* CalCCA Opening Comments at 4-10. Unless otherwise noted, all statutory references are to the Public Utilities Code.

2 As previously expressed and applied by the Commission, without "conced[ing] or limit[ing] any authority" the Commission has previously acknowledged and implemented shared jurisdiction "in a spirit of cooperation and comity". *See, e.g.,* D-05-08-038 at 25.

expressed an intent that reasonable distinctions exist (*e.g.*, that IOUs are potentially financially conflicted when serving both shareholders and ratepayers, while Community Choice Aggregators are not), and these distinctions must be acknowledged and meaningfully accommodated. The failure to do so is legal error.

Second, The Utility Reform Network ("TURN") incorrectly argues that Section 454.51 permits the Commission to order *general* long-term procurement by the IOUs with non-bypassable charges assigned to customers of all LSEs, including CCAs that do not elect to self-procure. (*See* TURN Comments at 2.) To the contrary, Section 454.51 only allows the Commission to impose non-bypassable charges on CCAs that elect not to self-procure their share of the *renewable integration* resources. Nothing in Sections 454.51 or any other statute expressly authorizes the Commission to impose non-bypassable charges for non-renewable integration resources through the IRP process.

B. IRP Consultant Costs

The Proposed Decision correctly concludes that, among other things, the Commission does not have authority to impose charges on CCA programs or CCA customers, and therefore all IRP-related consultant costs should be assigned to the IOUs. (*See* Proposed Decision at 121 [citing D.06-10-054].) Parties objecting to this allocation incorrectly argue that imposition of such costs would violate statutory cost-shifting prohibitions.

Cost-*shifting* prohibitions do not apply to this situation, as it is governed by cost-*allocation* rules, since these are not "stranded costs" but rather future costs principally associated with IOU-related *generation* activities. In addition, any proposal to impose costs on CCA customers through *distribution* rates must be subjected to rigourous scrutinty. This has not occurred in this proceeding, and even if it were to have occurred, the allocation of generation-related IRP costs through distribution rates would be found wanting, since such an outcome would violate competitive neutrality and cost-causation principles.[3]

C. The Clean Net Short Proposal

CalCCA, along with Peninsula Clean Energy, University of California ("Regents"), California Municipal Utilities Association ("CMUA"), and the Governor (through his veto message of Assembly Bill ("AB") 79), support letting the California Energy Commission ("CEC") complete its AB 1110 proceeding (16-CEC-05) to establish GHG reporting guidelines, rather than have the Commission "tip-the-scales" and pre-judge the outcome by adopting PG&E's Clean Net Short ("CNS") proposal. (*See, e.g.,* CMUA Comments at 3; Regents Comments at 3.) As the Regents note, the CEC's latest AB 1110 implementation proposal (which proposes annual calculation) was issued the same day as opening comments were filed in this proceeding. (*See* Regents Comments at 3.) The Utility Reform Network ("TURN") also rightly observes that adoption of PG&E's CNS proposal could lead to the CEC and the Commission "administer[ing] conflicting methodologies" that "cannot be easily reconciled." (TURN Comments at 9.) Moreover, the Regents and CMUA claim that PG&E's CNS proposal, submitted as an *ex parte* presentation to the CEC, does not meet the Commission's evidentiary standards for adoption and does not provide parties a full and fair opportunity to comment. (*See* Regents Comments at 2-3; CMUA Comments at 1.)

As even PG&E admits, PG&E's CNS proposal does not give credit to LSEs that provide, and more importantly pay to operate, the additional GHG-free energy delivered to California's electric grid, thus unfairly penalizing the very same LSEs that are helping California achieve its

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3 *See, e.g.,* D.97-08-056 at 8 ("[W]e will not permit allocations of generation cost to distribution customers."); *see also* D.13-03-032 at 71 and D.14-12-024 at 48 (holding that costs and benefits from generation-related efforts only for bundled customers must be allocated through generation rates, not distribution rates).

GHG-reduction goals. (*See, e.g.,* CMUA Comments at 6.) Finally, the Regents state that it is not clear that the "complex calculations and the exponential increase in necessary data" to implement PG&E's CNS proposal could be met by the June 1 IRP filing deadline. (Regents Comments at 2.)

D. Standard and Alternative Plans

The Proposed Decision would adopt distinct filing requirements for LSEs based on a threshold of 700 GWh of annual load served. Southern California Edison Company ("SCE") submitted comments opposing this distinction, arguing that all LSEs, regardless of size, should be subject to the same IRP requirements. (*See* SCE Comments at 7-8.) SCE's argument for a "one size fits all" approach is merely a statement of its preference, and is unsupported by legal authority or record evidence. Moreover, SCE's argument is at odds with Sections 454.51 and 454.52, which clearly authorize – and require – different IRP requirements for different categories of IRPs. The 700 GWh threshold has been well established in this proceeding,[4] is consistent with statutory principles,[5] and should be maintained as written in the Proposed Decision. Moreover, parties' attempts to impose additional requirements on Alternative IRPs should be rejected. Any additional requirement should be considered after the test year, when empirical evidence can be brought forward to support the need for such additional requirements.

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4 The 700 GWh threshold was proposed by the Energy Division in the May 16, 2017 *Staff Proposal on Process for Integrated Resource Planning*, and has been thoroughly discussed by parties through multiple rounds of subsequent comments.

5 In addition to statutory distinctives set forth in Sections 454.51 and 454.52, the 700 GWh threshold is also established as reasonable in Section 9621(a) (applicable to publicly owned utilitieis) and Section 454.52(e) (applicable to electrical cooperatives). *See also* Proposed Decision at 124; Conclusion of Law 5.

III. CONCLUSION

CalCCA thanks the Commission for its consideration of these reply comments.

Dated: January 22, 2018 Respectfully submitted,

/s/ David Peffer

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December 21, 2017

Via Regular Mail and Electronic Mail

Assigned Commissioner Liane M. Randolph
California Public Utilities Commission
505 Van Ness Avenues
San Francisco, CA 94102

Re: Draft Resolution E-4907 and the Resource Adequacy Proceeding

Dear Assigned Commissioner Randolph:

The California Community Choice Association ("CalCCA") is writing to you in your role as assigned commissioner in the California Public Utilities Commission's ("Commission") Resource Adequacy ("RA") proceeding (R.17-09-020). On December 8, 2017, the Commission's Energy Division released Draft Resolution E-4907 ("Draft Resolution") for public comment and set the Draft Resolution for Commission action at the January 11, 2018 meeting. Among other things, the Draft Resolution holds that, in order to comply with the year-ahead RA process, material changes to the certification process for Community Choice Aggregation ("CCA") implementation plans are needed. CalCCA appreciates the issues raised in the Draft Resolution, and looks forward to providing input to address these issues. However, CalCCA has serious concerns about procedural matters associated with the Draft Resolution. For example, changes proposed in the Draft Resolution appear to be based on untested factual assertions regarding cost-shifting, and the proposed changes were developed without stakeholder review and Commission consideration in a formal proceeding. Moreover, the proposed changes are presented to the Commission on an accelerated timeline under constrained conditions for public input, particularly during the holiday season. In short, CalCCA has various due process and procedural concerns with the Draft Resolution, particularly since the Draft Resolution would impinge on the statutory right of local governments to implement CCA programs.

Since the Draft Resolution bases its holding on issues central to the RA program, CalCCA requests your action as assigned Commissioner in the RA rulemaking proceeding. Specifically, for reasons summarized below, CalCCA requests that the Draft Resolution be withdrawn, and that the issues raised in the Draft Resolution instead be included within the scope of issues to be addressed in the RA proceeding. If expedited consideration of these issues is warranted, a separate track could be established to facilitate early adoption of a Commission decision. Addressing these issues in a formal Commission proceeding will remedy due process and other procedural concerns associated with the Draft Resolution. To facilitate formal consideration of CalCCA's request, several CCA programs have prepared and will be filing a motion in the RA proceeding.

The RA Proceeding Provides The Appropriate Forum

The Commission's October 4, 2017 Order Instituting Rulemaking in R.17-09-020 ("OIR") states that the Commission will use the RA proceeding to "oversee the resource adequacy program" and "make any changes and refinements to the program."[1] Overseeing the RA program, as described in the OIR, expressly includes a review of whether the Commission should "re-examine the basic structure and processes of the Commission's RA program."[2] The Commission notes in the OIR that its approach in addressing RA program changes through an active ratesetting proceeding is in line with previous RA proceedings which "served as the forum for RA decisions."[3]

The actions required by the Draft Resolution are based on RA-related issues, and yet these issues are not being considered in the RA proceeding's ratesetting forum. Instead, important changes that will affect the RA program are being considered without meaningful stakeholder input or open discussion in the RA proceeding. Making reference to "[p]otential unquantifiable bundled ratepayer savings due to elimination of cost shifting of resource adequacy costs,"[4] the Draft Resolution reviews RA cost allocation issues independent of the RA proceeding. Material proposed changes to the CCA implementation plan appear to be grounded in confidential, untested communication from one investor-owned utility ("IOU").[5] Importantly, there was no invitation to a broader group of stakeholders in the development of the Draft Resolution's supporting facts or for advanced input on the Draft Resolution's proposed changes and solutions. Indeed, CalCCA and other interested parties were not made aware of these matters until the release of the Draft Resolution.

CalCCA believes that the Draft Resolution's characterization of RA-related costs as "potential" and "unquantifiable" illustrates the preliminary nature of the Draft Resolution's examination, and highlights the need for formal review in a proper forum. A formal proceeding provides the proper context within which substantive proposals can be made, underlying assumptions discovered and tested, factual assertions examined and rebutted, and arguments advanced. In general, formal proceedings provide the best context and structure for ensuring due process requirements are satisfied.[6] The RA proceeding's OIR contemplates this context and structure.[7] This is illustrated by the fact that previous changes to CCA-related RA forecasting timelines and cost allocation issues were addressed within this structure. For example, in the most recent RA decision (D.17-06-027), the Commission examined proposals for RA forecasting and set a mandatory RA forecasting requirement for August of each year.[8]

---

1 OIR at 1.

2 *Id.* at 4.

3 *Id.* at 2 (referencing the previous RA proceedings R.11-10-023 and R.14-10-010).

4 *See* Draft Resolution at 1; *see also id.* at 7 (for reference to "potential" stranded costs).

5 *Id.* at 7.

6 *See People v. Western Air Lines Inc.*, 42 Cal. 2d 621, 632 (1954) (describing Commission due process requirements).

7 *See, e.g.,* OIR at 3 ("Because this proceeding has a broader scope and may include factual issues, it is preliminarily determined that evidentiary hearings will be needed in this proceeding.")

8 *See* D.17-06-027 at 30 and 33.

Findings And Conclusions In The Draft Resolution Must First Be Tested In The RA Proceeding

The Draft Resolution proposes significant changes to the CCA implementation process on the basis that such RA-related changes are necessary. The Draft Resolution directs that local governments launching CCA programs must submit implementation plans "on or before" January 1 of the year before the CCA intends to serve load, as well as submit RA forecasts ahead of January 1 in the following year.[9] Formed CCA programs that did not formally submit their implementation plan as of December 8, 2017 (the date on which the Draft Resolution was released) are required to adhere to these new procedures and timeline. This timeline materially and adversely affects local governments in the process of submitting implementation plans, materially delaying CCA implementation with no advance notice, formal process, or opportunity for input. In order to support and sustain these material effects, underlying assumptions and facts must first be tested in a formal proceeding. More directly, since the Draft Resolution's proposed changes impinge on the statutory right of local governments to implement CCA programs, as further described below, such changes can only be sustained if they are based on a robust, well-developed record.

As noted above, the Draft Resolution would impinge on the statutory right of local governments to implement CCA programs. In support of its proposal, the Draft Resolution references Assembly Bill ("AB") 117.[10] AB 117, as codified in the California Public Utilities Code, states explicitly that the Commission must provide the earliest possible effective date for CCA program implementation:

> The commission shall designate the *earliest possible effective date for implementation of a community choice aggregation program,* taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission.[11]

The successor to AB 117, Senate Bill ("SB") 790 states a clear intent of the Legislature to honor "the *right* of local governments to aggregate their electricity loads for the purpose of procuring and generating more renewable energy, expanding consumer choice, and greatly accelerating regional efforts to address climate change."[12] This right and the attendant aspect of "local control" was discussed this year by the United States Court of Appeals for the Ninth Circuit, which highlighted "the legitimate legislative purpose" of CCA programs in "reducing greenhouse gas emissions, providing electricity at a competitive cost, reducing energy consumption, and promoting rate stability, energy security, and energy reliability *through local control*."[13]

As written, changes to the implementation process described in the Draft Resolution would affect or implicate these statutory issues. As such, these changes should be carefully reviewed and examined in light of stakeholder input and normal regulatory processes.

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9 *See* Draft Resolution, Appendix B.

10 *See* Draft Resolution at 2.

11 Cal. Pub. Util. Code § 366.2(c)(8) (emphasis added).

12 *See* SB 790 Section 2(j) (emphasis added).

13 *Schmid v. Sonoma Clean Power*, 673 F. App'x 785, 786 (9th Cir. 2017) (unpublished, emphasis added).

In light of these matters, CalCCA requests that you, as assigned Commissioner in the RA proceeding, collaborate with the Energy Division to withdraw the Draft Resolution and instead set the issues raised in the Draft Resolution for consideration in the RA proceeding. An open rulemaking proceeding – where stakeholders can robustly engage, examine the evidence, and make their legal arguments – is the appropriate forum for the proposed changes described in the Draft Resolution.

Thank you for your consideration of this request.

Sincerely,

Dawn Weisz
President, CalCCA

Copy (via e-mail): CPUC President Michael Picker
CPUC Commissioner Martha Guzman Aceves
CPUC Commissioner Carla J. Peterman
CPUC Commissioner Clifford Rechtschaffen
CPUC Executive Director, Tim Sullivan
CPUC Energy Division Director, Ed Randolph
Service Lists: R.17-09-020
R.03-10-003
R.17-06-026
R.16-02-007

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

MOTION OF THE CCA PARTIES TO SUPPLEMENT COMMENTS ON THE ORDER INSTITUTING RULEMAKING, AND REQUEST FOR RULING SHORTENING TIME TO RESPOND

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Dated: December 21, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	))))))	Rulemaking 17-09-020 (Filed September 28, 2017)

MOTION OF THE CCA PARTIES
TO SUPPLEMENT COMMENTS
ON THE ORDER INSTITUTING RULEMAKING,
AND REQUEST FOR RULING SHORTENING
TIME TO RESPOND

I. INTRODUCTION

Pursuant to Rule 11.1 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the City of Lancaster ("Lancaster"), Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority ("PCE"), Silicon Valley Clean Energy Authority ("SVCE"), and Sonoma Clean Power Authority ("SCP") (collectively, "CCA Parties") hereby submit the following motion to supplement comments on the Order Instituting Rulemaking ("OIR") in this proceeding. The CCA Parties move to supplement their comments on the OIR in order to request consideration in this proceeding of issues raised in Draft Resolution E-4907, issued for comments on December 8, 2017 and currently set for Commission action on January 11, 2018 ("Draft Resolution"). As further described below, the Draft Resolution involves key issues related to the Resource Adequacy ("RA") program, and due process requires that these issues be addressed in the context of a formal proceeding. The CCA Parties also request that a ruling be issued shortening the time to respond to this motion.

II. DISCUSSION

A. Following the Prehearing Conference for this Proceeding, the Commission's Energy Division Released a Draft Resolution Involving Key RA-Related Issues

The OIR states the Commission will use this RA proceeding to "oversee the resource adequacy program" and "make any changes and refinements to the program."[1] This proceeding's oversight includes a review of whether the Commission should "re-examine the basic structure and processes of the Commission's RA program."[2] The Commission notes that its approach in addressing RA program changes through an active ratemaking proceeding is in line with the previous RA proceedings which "served as the forum for RA decisions."[3]

On December 8, 2017, the Commission's Energy Division served the Draft Resolution on the service list for this proceeding and other proceedings.[4] The Draft Resolution holds that, in order to comply with the year-ahead RA process, material changes to the certification process for Community Choice Aggregation ("CCA") implementation plans are needed. The Draft Resolution would establish a new timeline for RA filings, which impacts new and expanding CCA programs.[5] Making reference to "[p]otential unquantifiable bundled ratepayer savings due to elimination of cost shifting of resource adequacy costs," the Draft Resolution seeks to address, on the Commission's own initiative, RA cost allocation issues independent of the RA proceeding.[6] Based on a confidential, *ex parte* communication from one of the investor-owned utilities ("IOUs"), the Draft Resolution finds that the current RA program structure is

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1 OIR at 1.
2 *Id.* at 4.
3 *Id.* at 2 (referencing the previous RA proceedings R.11-10-023 and R.14-10-010).
4 R.03-10-003, R.17-06-026, R.17-09-020, and R.16-02-007
5 Appendices A and B of the Draft Resolution include a timeline of the CCA registration process, as proposed for revision in the Draft Resolution.
6 Draft Resolution at 1.

"potentially resulting in millions of dollars annually of stranded costs."[7] The Draft Resolution notes that "Energy Division issued data requests to PG&E confirming the existence of stranded costs. Responses to these data requests were confidential because of the market-sensitive information they contain."[8]

The CCA Parties appreciate the RA-related issues identified in the Draft Resolution. Indeed, in their comments on the OIR, the CCA Parties discuss related issues associated with load-migration to CCA programs, and request that these issues be considered within the context of the RA proceeding.[9] As such, the CCA Parties do not oppose addressing issues in the Draft Resolution; rather, the CCA Parties oppose the manner in which these issues are addressed and summarily disposed in the Draft Resolution. In short, the Draft Resolution would implement important changes that will affect the RA program, and yet these changes are being considered without meaningful stakeholder input or open discussion in the RA proceeding.

The procedures followed in the Draft Resolution are troubling from a due process perspective. Material proposed changes appear to be grounded in untested communication. Moreover, there was no invitation to a broader group of stakeholders in the development of facts and support for the Draft Resolution's proposed changes.

B. Due Process Requires that the Issues Raised in the Draft Resolution Be Addressed Within the RA Proceeding

The CCA Parties believe that the Draft Resolution's characterization of costs as "potential" and "unquantifiable" show the preliminary nature of the Draft Resolution's examination of issues impacting the RA program, and highlight the need for review of these

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7 *See id.* at 7.

8 *Id.* at 7.

9 *See* CCA Parties Comments on the OIR at 3-4.

issues in their proper forum – the RA proceeding. The RA proceeding's evidentiary process provides the proper context within which to receive and test facts, assess the details of RA program costs, and otherwise address RA-related issues.[10]

Due process requires that parties receive adequate notice and opportunity to be heard.[11] This is particularly necessary when material rights are involved. In this case, the Draft Resolution proposes significant changes to the CCA implementation process on the basis that RA-related changes are necessary. As written, changes to the implementation process described in the Draft Resolution would affect or implicate key statutory issues related to CCA programs. As such, these changes should be carefully reviewed and examined in light of stakeholder input and normal regulatory processes.

The CCA Parties note that RA program changes and cost examination through an active ratemaking proceeding is consistent with past Commission efforts. In the most recent RA decision (D.17-06-027), the Commission reviewed the existing forecast submission timeframe. After review of party proposals and an opportunity for stakeholder feedback, the Commission modified CCA RA forecasting requirements so that mandatory updates were provided in August of each year. Similar load forecast issues were also discussed in previous RA proceeding with determinations reached in D.16-06-045 and D.15-06-063.[12]

III. MOTION

In light of the existing Commission process for RA determinations highlighted above, the CCA Parties request that the Draft Resolution be withdrawn and that the issues raised in the

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10 OIR at 3 ("Because this proceeding has a broader scope and may include factual issues, it is preliminarily determined that evidentiary hearings will be needed in this proceeding.")

11 *Pac. Gas & Elec. Co. v. Pub. Utilities Comm'n*, 237 Cal. App. 4th 812, 859 (2015) (citing *People v. Western Air Lines Inc.,* 42 Cal.2d 621, 632 (1954)).

12 *See* D.16-06-045 at 49-53; D.15-06-063 at 36-41.

Draft Resolution be formally set for consideration in the RA proceeding. Consideration of these issues within the context of this ratesetting proceeding is consistent with the OIR and will provide affected parties with adequate notice and opportunity to be heard, as required for due process.

Pursuant to Rule 11.1(e), the normal response time to motions is 15 days, which would make responses to this motion due on January 3, 2018. The CCA Parties requests that the time for parties to respond to this motion be shortened to 6 days, so that responses will be due on or before December 27, 2017. The CCA Parties further request that the Commission rule on this motion at the earliest opportunity following receipt of responses (if any), or, as allowed under Rule 11(g), in advance of any responses. Adherence to this shortened schedule will allow this matter to be addressed without further exposing parties to an unduly expedited timeline. As it stands now, comments on the Draft Resolution are due on January 4, and the Draft Resolution is currently set for action at the Commission's January 11, 2018 meeting.[13]

Finally, in a letter dated December 21, 2017 (attached hereto), the California Community Choice Association ("CalCCA") requested that assigned Commissioner Randolph collaborate with the Energy Division to withdraw the Draft Resolution and instead address these issues in the context of this proceeding. The CCA parties fully support CalCCA's request, and believe that this motion provides the procedural basis for expressly including these issues within the scope of this proceeding.

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13 By email, dated December 20, 2017, the date for comments on the Draft Resolution was revised from December 29, 2017 to January 4, 2018, with clarification that no reply comments will be allowed.

IV. CONCLUSION

The CCA Parties thank the Commission for its consideration of the matters addressed in this motion.

Dated: December 21, 2017

Respectfully submitted,

/s/ Dan Griffiths

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Attachment A

Letter from the California Community Choice Association dated December 21, 2017

CalCCA
California Community Choice Association

Dawn Weisz, MCE
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Jan Pepper, Peninsula Clean Energy
Secretary

Joseph Moon, Apple Valley Choice Energy
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December 21, 2017

Via Regular Mail and Electronic Mail

Assigned Commissioner Liane M. Randolph
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1 OIR at 1.
2 *Id.* at 4.
3 *Id.* at 2 (referencing the previous RA proceedings R.11-10-023 and R.14-10-010).
4 *See* Draft Resolution at 1; *see also id.* at 7 (for reference to "potential" stranded costs).
5 *Id.* at 7.
6 *See People v. Western Air Lines Inc.*, 42 Cal. 2d 621, 632 (1954) (describing Commission due process requirements).
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As noted above, the Draft Resolution would impinge on the statutory right of local governments to implement CCA programs. In support of its proposal, the Draft Resolution references Assembly Bill ("AB") 117.[10] AB 117, as codified in the California Public Utilities Code, states explicitly that the Commission must provide the earliest possible effective date for CCA program implementation:

> The commission shall designate the *earliest possible effective date for implementation of a community choice aggregation program,* taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission.[11]

The successor to AB 117, Senate Bill ("SB") 790 states a clear intent of the Legislature to honor "the *right* of local governments to aggregate their electricity loads for the purpose of procuring and generating more renewable energy, expanding consumer choice, and greatly accelerating regional efforts to address climate change."[12] This right and the attendant aspect of "local control" was discussed this year by the United States Court of Appeals for the Ninth Circuit, which highlighted "the legitimate legislative purpose" of CCA programs in "reducing greenhouse gas emissions, providing electricity at a competitive cost, reducing energy consumption, and promoting rate stability, energy security, and energy reliability *through local control.*"[13]

As written, changes to the implementation process described in the Draft Resolution would affect or implicate these statutory issues. As such, these changes should be carefully reviewed and examined in light of stakeholder input and normal regulatory processes.

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9 *See* Draft Resolution, Appendix B.

10 *See* Draft Resolution at 2.

11 Cal. Pub. Util. Code § 366.2(c)(8) (emphasis added).

12 *See* SB 790 Section 2(j) (emphasis added).

13 *Schmid v. Sonoma Clean Power*, 673 F. App'x 785, 786 (9th Cir. 2017) (unpublished, emphasis added).

In light of these matters, CalCCA requests that you, as assigned Commissioner in the RA proceeding, collaborate with the Energy Division to withdraw the Draft Resolution and instead set the issues raised in the Draft Resolution for consideration in the RA proceeding. An open rulemaking proceeding – where stakeholders can robustly engage, examine the evidence, and make their legal arguments – is the appropriate forum for the proposed changes described in the Draft Resolution.

Thank you for your consideration of this request.

Sincerely,

Dawn Weisz
President, CalCCA

Copy (via e-mail): CPUC President Michael Picker
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CPUC Commissioner Carla J. Peterman
CPUC Commissioner Clifford Rechtschaffen
CPUC Executive Director, Tim Sullivan
CPUC Energy Division Director, Ed Randolph
Service Lists: R.17-09-020
R.03-10-003
R.17-06-026
R.16-02-007

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January 18, 2018

Via U.S. Mail and Electronic Mail

Mr. Ed Randolph
Director, Energy Division
California Public Utilities Commission
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San Francisco, CA 94102

Re: Reply Comments on Draft Resolution E-4907

Dear Mr. Randolph:

In accordance with the email from Suzanne Casazza, California Public Utilities Commission ("Commission") Energy Division, dated December 27, 2017, the California Community Choice Association ("CalCCA") submits these reply comments on Draft Resolution E-4907 ("Draft Resolution").

SUMMARY

The comments of the Los Angeles Community Choice Energy, Desert Community Energy and the Western Riverside Council of Governments (collectively "SoCal CCAs"), Pioneer Community Energy, and the cities of King City, San José and Solana Beach paint a clear picture of the Draft Resolution's impacts. These communities have collectively redirected their personnel, conducted hundreds of meetings, worked many hours, and invested millions of dollars to seek the benefits that Community Choice Aggregation ("CCA") programs offer their residents and businesses. The communities relied on a longstanding implementation framework they reasonably expected to remain viable. They worked in good faith with the investor-owned utilities ("IOUs") to understand their obligations and, in some cases, confirmed the timing of those obligations while the Draft Resolution was being developed. With no warning from the IOUs with which they were working—the same IOUs that now profess adequate notice was provided—they are being required to delay their implementation dates, undertake further efforts, and incur substantial expense to respond to conclusions they have been unable to discuss, investigate and, if necessary, disprove.

With this picture in mind, CalCCA appreciates the opportunity afforded by the Commission to provide reply comments. While a two-stage comment period on the Draft Resolution is insufficient to satisfy due process and other procedural concerns, reply comments nevertheless give parties an opportunity to comment on common themes with reference to the Draft Resolution. Three common themes emerge from opening comments, all of which point to the need for further work, collaboration and consideration of alternative outcomes.

First, more work is needed to address the various issues facing the Commission and the IOUs as the electric industry seeks to integrate and accommodate the expansion of CCA programs. Many stakeholders state that the Draft Resolution does not sufficiently identify what the year-ahead Resource Adequacy ("RA") problem is, explore mitigating factors, and analyze the appropriateness of the remedy set forth in the Draft Resolution. While the Draft Resolution has served to sharpen interest among stakeholders, more work is needed.

Second, there was widespread concern about procedural flaws with the Draft Resolution, and the significant hardship that would occur as a result of the process contemplated in the Draft Resolution. Only the Joint IOUs and the Coalition of California Utility Employees ("CUE") assert that the Draft Resolution's approach is compatible with due process. While generally sympathetic to the underlying concerns in the Draft Resolution, The Utility Reform Network ("TURN") expresses a view held by nearly all commenters:

> [I]t is problematic for the Commission to include [rules] in a Draft Resolution not tied to activity in an ongoing active proceeding. The lack of advance notice and absence of an open record complicates the justification for significant changes in policy and practice. As a general matter, the Commission should undertake consideration of these types of changes as part of a rulemaking or investigation.[1]

The problems associated with the Draft Resolution's process are exacerbated by the fact that the hardship will be swift and significant, a point made by many emerging CCA programs in their comments. This underscores the need for due process in resolving the issues posed by the Draft Resolution.

Third, there was nearly universal support for an alternative outcome. In general terms, this outcome would allow, for 2018 only, the transfer of surplus RA capacity currently held by the IOUs from the IOUs to newly-forming CCA programs – a process similar to one the Commission previously adopted on an interim basis in D.10-03-022 in response to the reopening of direct access ("DA"). Even the IOUs express a willingness to arrive at an alternative outcome for 2018, although preferring a negotiated transfer of capacity rather than a more ready-made alternative outcome.

In general, the themes advanced in opening comments support the two-part approach described by CalCCA in its comments. Under the first part, near-term RA-related matters (*i.e.*, for 2018) would be expeditiously adopted in an appropriate proceeding under temporary action comparable to that which was approved by the Commission in D.10-03-022. The second part of the approach (*i.e.*, action beyond 2018) would be addressed in a reasoned and timely process in a formal proceeding, presumably the RA proceeding. CalCCA looks forward to openly and fairly addressing these issues in a manner that stays true to the indifference principle and due process requirements.

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1 TURN Comments at 2.

REPLY COMMENTS

I. Consensus Exists For Implementation Of An Alternative In 2018

Nearly every party expressed the belief that a work-around or alternative outcome should be implemented in 2018 in an expedited process that meets due process requirements. Even the IOUs expressed support, although the IOUs stated they want the *option*, but not the *obligation*, to negotiate an alternative outcome.[2]

The Commission should reject the IOUs' work-around approach, and consider in an appropriate proceeding the alternative outcome described by numerous commenters. 350 Bay Area summarizes this outcome by first observing that the Commission previously addressed a similar RA issue in D.10-03-22, where Electric Service Providers ("ESPs") "paid the IOU's directly for the capacity for the first year – at which point the normal planning and procurement cycle took over."[3] The Alliance for Retail Energy Markets ("AReM") similarly notes that "CCA formation is not the first instance of load departing IOU service"[4] and suggests that the D.10-03-022 process could be applied, making the Draft Resolution's restrictions on new and expanding CCAs unnecessary.[5] A number of other parties express similar support for the outcome produced in D.10-03-022.[6] CalCCA also mentioned this as a possible alternative outcome, noting that this and related issues could be expeditiously considered in the RA proceeding.[7]

II. Comments Describe Significant, Negative Impacts Associated With The Draft Resolution

Opening comments from local governments and other stakeholders describe the significant impact that the Draft Resolution poses on California residents, ratepayers, and emerging CCA programs. AReM expresses "concerns about the Draft Resolution's excessive and unwarranted impact on the development of CCA programs." and notes that an effect of the Draft Resolution's schedule is that "any nascent CCA that has not yet filed an Implementation Plan is effectively forestalled until at least 2020 to begin its operations."[8] The Sierra Club sees "significant policy implications for new and expanding CCAs as well as the municipal and county government that support them."[9]

These negative impacts are described by numerous local governments – spanning a wide range of California's demographics and geography. The SoCal CCAs raise concerns about the disruptive

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2 *See* Joint IOU Comments at 5.
3 350 Bay Area Comments at 2.
4 AReM Comments at 6.
5 AReM Comments at 7.
6 *See* 350 Bay Area comments at 2; Sierra Club Comments at 3; San Francisco Comments at 8; AReM Comments at 6-7 and SoCal CCAs Comments at 13-14.
7 *See* CalCCA Comments at 12.
8 AReM Comments at 2.
9 Sierra Club Comments at 2.

impact of the Draft Resolution on CCA programs that "are near the finish line for development and are ready for launch" and have invested large amounts of time and funds in the careful planning and development of these programs.[10] Pioneer Community Energy notes the undue burden on communities investing resources in CCA implementation.[11] San José expresses concern with the fact that it has expended significant time and funds in preparing to launch its CCA program during the summer of 2018.[12] King City states that a key preventative component of its plan for safe neighborhoods is the much-needed expansion of neighborhood street lighting through the King City CCA.[13] San Francisco notes that the Draft Resolution could substantially affect the ability of existing CCAs to phase-in additional customers.[14] Solana Beach notes harm in implementing its CCA plans and its ability to partner with local jurisdictions.[15]

The negative harm described by these communities throughout California exemplifies the harmful consequences that would result under the Draft Resolution, and highlights the need for a measured approach that provides sufficient consideration of these important issues.

III. Comments Raise Broad Concerns Over Due Process And Other Procedural Matters

Comments on the Draft Resolution raised broad procedural concerns, including: the need for incorporation in a formal proceeding (such as the RA proceeding), the extent of opportunity to be heard, and the requirement under law that local governments be provided the earliest possible effective date for implementation.

A. Formal Proceeding.

Many comments raised concerns with utilizing a Draft Resolution as the means to address long-term issues. As noted by the Sierra Club, "The resolution process denies the Commission and stakeholders the opportunity to develop a public record, to solicit and vet alternative proposals, and to facilitate robust stakeholder debate."[16] CalCCA and San Francisco, among others, state that the Commission's process violates the requirements of the Public Utilities Code and the Commission's Rules of Practice and Procedure and impermissibly modifies previous Commission decisions.[17] AReM states that the RA proceeding is the best forum in which the "issue and magnitude of any potential cost shift could be examined through a robust stakeholder process – rather than through the Draft Resolution, which provides for very little meaningful stakeholder input."[18] Sierra Club and Shell Energy both propose

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[10] SoCal CCAs Comments at 6-7.
[11] *See* Pioneer Community Energy Comments at 2.
[12] *See* City of San José Comments at 1.
[13] *See* King City Comments at 2.
[14] *See* San Francisco Comments at 10.
[15] *See* City of Solana Beach Comments at 2-3.
[16] Sierra Club Comments at 2. *See also* TURN Comments at 2-3 (describing the problematic nature of not addressing a key issue in an ongoing active proceeding.)
[17] *See, e.g.,* CalCCA Comments at 7-8; San Francisco Comments at 5-6.
[18] AReM Comments at 3.

the RA proceeding as a means to address issues in the Draft Resolution,[19] and Shell Energy references past comments from Pacific Gas and Electric Company ("PG&E") seeking review of these issues within the RA proceeding.[20]

Interestingly, when the Joint IOUs propose modifications to the Draft Resolution, and note concerns with the Draft Resolution's rigid January 1 launch, the Joint IOUs also ask the Commission to "clarify how the annual Local RA requirement should be addressed as there could be ambiguity as to whether Local RA should be covered by the CCA or the utility."[21] This request for clarification on cost allocation issues, such as "how costs or contracts will be allocated to CCA customers" is the very question that should be addressed in the context of a formal proceeding, and should not be left to bilateral negotiations, as proposed by the IOUs.

Finally, it will be important as part of any formal proceeding to examine all RA-related issues that may be implicated by the departure of load to CCA programs. As described above, the IOUs state in their opening comments that they want the option, but not the obligation, to negotiate an alternative outcome.[22] The IOUs' comments highlight an issue. Specifically, in the context of RA products, the IOUs have market power and in certain respects operate as oligopolies, controlling the supply of RA products. Parties have, from time to time, expressed concerns about the possible withholding of RA products by the IOUs.[23] Given the IOUs' position in the RA market, it would be wrong to grant the IOUs' request for an option, but not an obligation, to implement an alternative outcome. Granting the IOUs' request would exacerbate market power-related concerns.

B. Opportunity to Be Heard

Several comments describe the Draft Resolution's insufficiency in providing stakeholders the opportunity to be heard. AReM states that the comment process in the Draft Resolution is "severely circumscribed" and highlights that parties are directed to focus on "factual, legal or technical errors" rather that understand the full scope of underlying RA issues that the Draft Resolution seeks to address, or present any meaningful data on those issues.[24] AReM also points to *Cal. Trucking Ass'n v. Pub. Utilities Comm'n*, 19 Cal. 3d 240, 244 (1977) for the proposition that an opportunity to be heard "implies at the very least that a party must be permitted to prove the substance of its protest rather than merely being allowed to submit written objections to a proposal."[25]

Here, the Draft Resolution was based on confidential information not available to parties. As the Local Government Sustainable Energy Coalition ("LGSEC") notes, "no local governments or CCAs

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19 Sierra Club Comments at 2.
20 Shell Energy Comments at 2-3.
21 Joint IOU Comments at 4.
22 *See* Joint IOU Comments at 5.
23 *See* Shell Energy Comments at 3. *See also* CCA Parties' Comments (R.17-09-020) at 3-4 (October 30, 2017). *See*
24 AReM Comments at 4. *See also* Organizing for Action ("OFA") - Contra Costa Chapter at 1 (raising concerns with adequate notice).
25 *Cal. Trucking Ass'n v. Pub. Utilities Comm'n*, 19 Cal. 3d 240, 244 (1977)

were contacted in preparation of the Draft Resolution."[26] There is no discovery or hearings to address PG&E's information provided to the Energy Division, and, as noted by Shell Energy, "reliance on undisclosed, untested confidential information as the basis for its recommendation is legally questionable."[27] Sierra Club states that, since the directive in D.05-12-041 "is over a decade old, there is no justification for a hasty solution rather than providing stakeholders the opportunity to propose and vet alternative solutions."[28] CalCCA supports these views. The Commission should give parties a fair opportunity in an appropriate proceeding to be heard on issues in the Draft Resolution.

C. Earliest Possible Effective Date

AReM notes that the outcome proposed in the Draft Resolution stands in contrasts with direction for the "earliest possible effective date" for implementation of CCA programs.[29] AReM notes that it is doubtful that the delay caused to launching CCAs without adequate support would comply with that obligation.[30] The SoCal CCAs also make this point – a point especially relevant to their respective situations.[31]

IV. Comments That Summarily Dismiss Due Process Concerns Are Unavailing

Only two parties (the IOUs and CUE) believed the Draft Resolution process met due process requirements. [32] Tellingly, neither party offered legal support or substantive analysis for their summary statements. CUE unreservedly states that "[t] here is no question that Due Process will be provided and that parties will receive ample opportunity to be heard" because "[t]he Commission granted two requests for extension at the behest of CCA parties and will receive both opening and reply comments…in addition to the letters and other forms of correspondence submitted by CCA parties."[33] The summary statements from the IOUs and CUE are unavailing. Due process concerns associated with the Draft Resolution are substantial.[34] The Commission has established the requirements for due process, and the Draft Resolution did not meet these requirements.

V. The IOUs Fail To Provide Information Supporting Supposed Cost-Shifting

Despite the fact that the IOUs exclusively hold key cost-related information, nowhere in their comments do the IOUs attempt to justify claims in the Draft Resolution that short-term RA-related cost-shifts rise to the level of material. The IOUs claim that the problem is "significant and would

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26 LGSEC Comments at 2.
27 Shell Energy Comments at 2.
28 Sierra Club Comments at 2.
29 AReM Comments at 3.
30 AReM Comments at 6.
31 *See* SoCal CCA Comments at 7-8.
32 Joint IOU Comments at 6.
33 CUE Comments at 2.
34 *See* CalCCA Comments at 3-7 (outlining numerous due process-related flaws with the Draft Resolution).

constitute a large cost burden" but they fail to describe the amount, nature and mitigating elements associated with this supposed large cost burden.[35] The IOUs likewise claim that they "have had to make incremental purchases of RA to satisfy the year-ahead obligations for the load that is about to be served by a CCA" but again they fail to describe the amount, nature and mitigating elements associated with these purchases.[36] Instead of providing supporting information, , the IOUs prefer to make broad, unqualified, and prejudicial statements about untested "subsidies" and "cost-shifts."[37] As other parties also stated,[38] untested and unsupported claims of cost-shifts by the IOUs, as market participants, are insufficient to justify the material actions described under the Draft Resolution.

The IOUs' silence on these key matters only serves to leave these issues of fact unanswered.[39] This silence is particularly deafening with regard to Southern California Edison Company ("SCE") and San Diego Gas & Electric Company ("SDG&E"). One of the critical evidentiary shortcomings within the Draft Resolution is that it relies solely on data provided by one IOU to establish a far-reaching policy outcome that affects CCA programs in all three IOUs' service territories. SCE and SDG&E failed to supplement the record with any evidence to support the existence of the cost-shift issues underlying the Draft Resolution's concerns in their service territories. The result is a Draft Resolution based on insufficient and untested evidence with regard to PG&E, and zero evidence with regard to SCE and SDG&E.

VI. CalCCA Supports The CAISO's Call For Coordination

The CAISO emphasizes the need for coordination among the Commission, California Energy Commission ("CEC"), the CAISO and stakeholders.[40] CalCCA supports this request. Consideration in a formal proceeding is the best approach to achieving a fair outcome that is coordinated with stakeholders such as the CEC and the CAISO. As the CAISO notes, if a load-serving entity has an RA obligation, there are additional requirements, such as load migration information, to ensure that the RA obligations are reflected in the CAISO's systems and coordinated with other agencies.

VII. The IOUs Underscore Additional Problems With Blanket Implementation

In its opening comments, CalCCA describes various problems with a blanket launch date of January 1 for all CCA programs.[41] Not only does such an approach violate Section 366.2(c)(8), which requires an individual assessment of implementation plans, but a blanket approach also could create market distortions that adversely impact California customers and is difficult to administer, particularly during the holiday season. The IOUs describe additional problems. As stated by the IOUs, "[i]f multiple CCAs, with a significant number of customers, were to begin service during

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35 Joint IOU Comments at 2.
36 Joint IOU Comments at 2.
37 See Joint IOU Comments at 2.
38 *See* SoCal CCA Comments at 10-11; AReM Comments at 5-6; Shell Energy Comments at 2; and San Francisco Comments at 2.
39 *See* CalCCA Comments at 5 (listing specific issues of facts that are unresolved).
40 *See* CAISO Comments at 1.
41 *See* CalCCA Comments at 11.

January of Year 2, the utilities would experience delays in processing times because SCE and SDG&E's operations and systems are not designed to accommodate large-scale transitions within a short period of time."[42] CalCCA agrees; blanket implementation, especially in January, is inadvisable and fraught with problems.

CONCLUSION

Given the reasons provided above, the Commission should either deny or withdraw the Draft Resolution. CalCCA agrees with commenters that short-term RA issues associated with the formation of CCA programs should be addressed expeditiously, but in a manner that considers and harmonizes counterbalancing issues and that adheres to the Commission's due process requirements. The approach utilized by the Commission in D.10-03-022, or some variant thereof, appears to be a workable approach. Longer-term RA issues should be addressed in a more reasoned and deliberative manner in an appropriate proceeding, such as the Commission's RA proceeding.

Sincerely,

Beth Vaughan
Executive Director, CalCCA

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Service Lists: R.17-09-020
R.03-10-003
R.17-06-026
R.16-02-007

42 Joint IOU Comments at 4.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	))))))	Rulemaking 17-09-020 (Filed September 28, 2017)

MOTION FOR PARTY STATUS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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Dated: January 30, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	)	Rulemaking 17-09-020 (Filed September 28, 2017)

MOTION FOR PARTY STATUS
OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Pursuant to Rules 11.1 and 1.4(a)(4) of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the California Community Choice Association ("CalCCA") respectfully moves for party status in this proceeding.

I. BACKGROUND

CalCCA is a nonprofit organization formed in June of 2016 to represent the interests of California's Community Choice Aggregation ("CCA") programs in regulatory and legislative matters. As an organization representing the views of CCA programs in California, CalCCA has a direct interest in resource adequacy ("RA") program developments that impact the structure within which CalCCA's members operate. The Scoping Memo issued in this proceeding identifies certain time-sensitive RA issues for consideration in Track 1.[1] One issue is particularly important to CalCCA: "[W]hether participation in the year-ahead RA showing should be required in order for an [load-serving entity ("LSE")] to serve load in the following year, and

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1 *See Scoping Memorandum and Ruling of Assigned Commissioner and Administrative Law Judge*, dated January 18, 2018, at 5-7.

other resource adequacy and potential cost allocation issues that arise as a result of load migration."[2] This issue is important to CalCCA for a number of reasons, not least of which is the fact that CalCCA has been extensively involved in comments on Draft Resolution E-4907, which proposes to address similar issues. In that context, CalCCA has urged the Commission to consider RA-related load migration issues within this proceeding. As such, CalCCA is pleased to see that this issue, and related issues, are set for Track 1 consideration in this proceeding. More broadly, however, CalCCA also has an interest in working to address RA program issues so there is no unnecessary impact on CCA growth and development.

Therefore, CalCCA's participation in this proceeding is appropriate and necessary in order to ensure that the interests of its members are effectively represented. CalCCA anticipates that it will collaborate and coordinate positions with its members.

II. PARTY STATUS

CalCCA's participation in this proceeding will not prejudice any party, and will not delay the schedule or broaden the scope of issues in this proceeding. As described herein, CalCCA has a material interest in the matters being addressed in this proceeding. For the reasons stated above, CalCCA seeks party status.

All correspondence and communication should be directed to the following representative:

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[2] Scoping Memo at 6 (Issue 4.a.).

CalCCA requests that the assigned administrative law judge issue a ruling authorizing CalCCA to intervene in this proceeding and designating CalCCA as an interested party using the name and address set forth above for correspondence and communication.

III. CONCLUSION

For the reasons stated above, CalCCA respectfully requests that the Commission grant CalCCA's motion for party status in this proceeding.

Dated: January 30, 2018

Respectfully submitted,

/s/ Scott Blaising

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

COMMENTS OF THE CCA PARTIES ON THE SCOPING MEMO AND RULING

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

COMMENTS OF THE CCA PARTIES
ON THE SCOPING MEMO AND RULING

Pursuant to the January 18, 2018 *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* ("Scoping Memo") in this proceeding, and the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, East Bay Community Energy ("EBCE"), the City of Lancaster ("Lancaster"), Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority ("PCE"), Silicon Valley Clean Energy Authority ("SVCE"), and Sonoma Clean Power Authority ("SCP") (collectively, "CCA Parties") hereby submit the following comments on the Scoping Memo.

I. INTRODUCTION AND SUMMARY

Among other things, the Scoping Memo outlines the proceeding scope and schedule, provides notice of staff proposals, and solicits party proposals for additional resource adequacy ("RA") program changes for the 2019 compliance year. The CCA Parties commend the assigned commissioner and administrative law judge for framing the Scoping Memo in a manner that allows for the examination of time-sensitive RA issues on an expedited basis, while preserving procedural safeguards and process. This balance is particularly important given the need for review in a formal proceeding of the issues raised by Draft Resolution E-4907 ("Draft Resolution").

Through the California Community Choice Association ("CalCCA"), the CCA Parties have addressed RA-related issues implicated by the Draft Resolution. Importantly, CalCCA has advocated that this proceeding, and in particular Track 1, should be used as the venue to address time-sensitive RA-related issues associated with the implementation of Community Choice Aggregation ("CCA") programs. The CCA Parties agree.[1] As further discussed below, the CCA Parties support the Scoping Memo's determination that key RA programmatic questions related to load migration should be addressed expeditiously within this proceeding, not through the Draft Resolution.[2] These key RA programmatic questions properly fit within this proceeding, as the RA proceeding's Order Instituting Rulemaking ("OIR") contemplates this proceeding for "any changes and refinements" to the RA program, and the OIR cites the Commission's long history of using the RA rulemakings as the "forum for RA decisions."[3]

The Scoping Memo's inclusion of these issues is important because a formal proceeding provides the proper context within which substantive proposals can be made, factual assertions examined and rebutted, arguments advanced, and due process requirements can be satisfied. Moreover, use of memorandum account treatment can ensure that the investor-owned utilities' ("IOUs") cost allocation concerns do not unnecessarily trump process and procedure. Further, given the direct overlap of Cost Allocation Methodology ("CAM") issues with multi-year RA

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1 *See, e.g,* Motion of the CCA Parties to Supplement Comments on the Order Instituting Rulemaking at 3-4 (December 21, 2017).

2 *See* Scoping Memo at 6-7 (scoping such programmatic questions within Track 1).

3 OIR at 1-2.

and centralized buying in Track 1, and the related potential for anti-competitive impacts, the CCA Parties encourage the inclusion of the CAM within Track 1 of this proceeding.

II. COMMENTS

A. Track 1's Time-Sensitive Review Of RA Issues Minimizes The Need For Action Through The Draft Resolution

The Scoping Memo divides the proceeding into three separate tracks. Track 1 will address refinements to the Commission's RA program and be resolved on a time-sensitive schedule leading to a decision in Spring of 2018.[4] A "top priority" issue for Track 1 is "whether" participation in the year-ahead RA showing should be required to start serving load in the following year.[5] Track 1 will also review necessary RA program reforms, as well as "any other time sensitive issue identified."[6] Party proposals for the RA program, and the year-ahead showing issue, is scheduled to start on February 16, 2018.[7]

The scope and expedited treatment of key load migration issues minimize the need for action through the Draft Resolution, and allows the Draft Resolution to be modified in a way that is complementary to action contemplated in this proceeding. As originally written, the Draft Resolution would make determinations on the same or similar RA program issues, including year-ahead RA showing participation, at the Commission's February 8 business meeting.[8] Under the original timeline, this would mean that the RA showing determination will have already been made nine days before parties are provided the opportunity to propose "whether" additional RA year-ahead showing requirements should exist, and how the requirements should be structured.

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4 Scoping Memo at 13.

5 *Id.* at 6.

6 *Id.*

7 *Id.*

8 December 27, 2017 e-mail from the Energy Division to R.17-06-026 service list.

Issuance of the Scoping Memo allows the Draft Resolution to be modified in a manner that identifies key RA-related issues, sets those issues for determination in the RA proceeding and preserves cost-allocation matters for future disposition. In short, the Draft Resolution should be modified to be complementary with the Scoping Memo's timeline and process for resolving Track 1's time-sensitive issues.[9]

The CCA Parties appreciate that CalCCA has addressed these matters in general within the procedural process associated with the Draft Resolution. The CCA Parties echo CalCCA's comments, and in particular acknowledge efforts by the Energy Division to highlight time-sensitive issues. Issuance of the Scoping Memo, and the schedule for Track 1, accomplishes the Draft Resolution's goal: expedited resolution. Party proposals are due next month and will result in a conclusion in the spring – considerably ahead of the October year-ahead filing obligation timeframe. Moreover, even with respect to 2018-related issues, Track 1 can and should be used to establish the record for activities contemplated in the Draft Resolution, as generally described in Section B, below. In this way, the Draft Resolution and this proceeding can operate in concert to address these issues.

The CCA Parties also desire, through these initial comments, to put forward additional thoughts as to how these time-sensitive matters can be addressed without adversely affecting CCA implementation or compromising cost-allocation issues. The CCA Parties look forward to advancing a more fleshed-out proposal on February 16, ideally in concert with the IOUs.[10]

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[9] Draft Resolution at 6-10, 16 (directing year-ahead participation before serving load).

[10] *See* Scoping Memo at 12 (listing February 16, 2018 as the date by which Track 1 proposals are to be filed).

The RA proceeding, and the Scoping Memo's timeline, allows parties an adequate opportunity to consider and address proposals, while also being mindful of the need for prompt action. The Scoping Memo recognizes that parties may need to examine RA program cost claims, and provides for evidentiary hearing and discovery in a manner consistent with the Commission's rules. The Scoping Memo's approach addresses a major concern expressed with the Draft Resolution, namely, that determinations on RA cost allocation and new RA showing requirements are proposed to be made with sole reference to untested, confidential data of a single IOU.[11] The RA proceeding's process will provide a proper venue and underlying record for decisions on RA program requirements.

The Scoping Memo's Track 1 resolution is consistent with past Commission actions in the RA proceedings. In D.15-06-063, the Commission was presented with the opportunity to make changes to the CAM. Since the CAM mechanism changes "have been scoped into the 2014 [Long-Term Procurement Plan ("LTPP")] LTPP Proceeding," the Commission determined to "defer consideration of this issue to the LTPP proceeding."[12] Similarly in D.15-06-063, the Commission reviewed proposals for Flexible RA requirement changes, but since Phase 2 of the proceeding would be considering flexible product issues, the Commission determined it would be "more appropriate and effective" to address these issues there.[13]

In light of the Scoping Memo, the Commission should restructure its February 8, 2018 consideration of the Draft Resolution so that immediate cost-allocation issues are preserved through memorandum account treatment and substantive RA program changes are procedurally

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11 *See* Draft Resolution at 7 (for reference to confidential data).

12 D.15-06-063 at 30.

13 *Id.* at 46.

addressed in Track 1 of this proceeding. Resolution of these changes through Track 1, where a record can be developed and party claims can be reviewed in a transparent manner, is more appropriate and effective.[14] By preserving cost-allocation issues through the authorization of memorandum accounts, the Draft Resolution will address a time-sensitive matter without compromising process and procedure.

B. Memorandum Account Treatment Can Be Used To Preserve Time-Sensitive Cost-Allocation Issues

As noted above, the CCA Parties, ideally in concert with the IOUs, plan to advance a more detailed proposal on February 16. In light of the Commission's possible consideration of the Draft Resolution at its February 8 meeting, the CCA Parties offer these initial comments as to how time-sensitive cost-allocation issues can be preserved so that the expected June 2018 Track 1 decision in this proceeding can be used to more effectively and fairly address time-sensitive RA-related issues associated with CCA programs.

A parallel for memorandum account treatment is being addressed in Application 16-11-005, the IOUs' consolidated application to recover above-market costs associated with tree mortality power purchase agreements in compliance with Senate Bill ("SB") 859 and Resolution E-4805. In that proceeding, the IOUs are attempting to establish a cost-allocation mechanism for procurement made on behalf of all customers, including customers that are departing for CCA programs. Since the outcome in that proceeding is expected to occur after the IOUs' incurrence of certain costs, the IOUs have established memorandum accounts into which the IOUs are recording costs that subsequently may be allocated based on a Commission decision.[15]

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[14] *See* CalCCA Comments on Draft Resolution E-4907 at 11-12.

[15] *See, e.g.,* Southern California Edison Company ("SCE") Advice Letter 3497-E-A (establishing the Biomass Memorandum Account (BioMASSMA)).

Memorandum accounts are effective ways to preserve costs for subsequent disposition.[16] By establishing memorandum accounts in this case, the Commission can avoid the unnecessary rush to alter CCA program implementation processes while the Commission works in this proceeding to address underlying RA-related issues.

As such, the CCA Parties urge the Commission, through the Draft Resolution, to authorize the IOUs to establish memorandum accounts to track actual RA-related costs associated with 2018 load migration to CCA programs. In doing so, the Commission will preserve this issue, and allow parties to thoughtfully (yet expeditiously) address this issue. On February 16, the CCA Parties plan to put forth a proposal as to how actual costs may be determined and assigned to responsible CCA programs. For now, preserving costs, through memorandum accounts, should satisfy concerns about possible cost-shifting.

C. CAM Should Be Addressed Within Track 1 Due To Direct Overlap With Multi-Year And Centralized Buying Issues

Within the discussion of potential RA program reforms in Track 1, the Scoping Memo states that the RA program reforms "may include central buyers" or a "multi-year procurement framework."[17] The large IOUs are provided as an example of a central buyer.[18] Since Community Choice Aggregators are public agencies with general procurement autonomy granted by statute, the CCA Parties are concerned that this language in the Scoping Memo could potentially be interpreted as counter to the approach specified by the Legislature. In Public Utilities Code Section 366.2(a)(5), a Community Choice Aggregator shall be "solely

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[16] *See, e.g.,* SCE AL 3491-E-A at 11 ("Disposition of amounts recorded in the BioMASSMA will be determined by the Commission in a future application.").

[17] Scoping Memo at 6.

[18] *Id.* at 4.

responsible" for all generation procurement activities, unless expressly authorized by statute.[19] Similarly, Section 380 states that RA procurement authority and responsibility rests with *each* Load Serving Entity, which explicitly includes Community Choice Aggregators.[20] Proposals related to these RA program reforms should be considered within this statutory context, and should align with CCA procurement autonomy.

The proposed considerations of multi-year RA and centralized buying in Track 1 have a direct overlap with the CAM. CCA customers are faced with costs stemming from IOUs' long-term commitments through the CAM. As highlighted in past comments,[21] multi-year RA requirements can pose anti-competitive dynamics, since CCAs are not guaranteed cost recovery for the cost of RA capacity. Given the potential for anti-competitive impacts on CCA programs, a review of CAM structure is needed as part of Track 1. Thus, the CCA Parties request that "potential reform to the CAM" be considered within Track 1 of this proceeding.

D. IOU Solicitation Issues Are Time-Sensitive And Should Be Addressed As Part Of Track 1

In the Scoping Memo, Track 1 involves consideration of "any time-sensitive issue" and any "RA program reforms necessary to maintain reliability while reducing potentially costly backstop procurement."[22] Any discussion of year-ahead RA procurement must include a review of the IOUs' solicitation processes for capacity to meet these year-ahead procurement obligations. Resolution of these issues through Track 1 is needed to reach a determination ahead of the October year-ahead filing obligation timeframe. Since considerable load departure from

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19 All further statutory references are to the Public Utilities Code, unless otherwise noted.

20 *See, e.g.,* Section 380(c)-(k) (Setting RA responsibilities for "each" LSE).

21 *See* Reply Comments of CCA Parties on Phase 3 Proposals in R.14-10-010 at 5 (March 24, 2017).

22 Scoping Memo at 6.

the IOUs in recent years can result in IOU RA capacity volumes that are in excess of regulatory requirements, the Commission should examine under what conditions excess RA capacity volumes are retained beyond the year-ahead RA compliance deadline, what impact the retention of excess volumes would have on customers, and whether market power issues arise.[23]

A review of the solicitation process for excess volumes should be conducted since past processes, which are lengthy and conclude in October,[24] cause market inefficiencies and in turn create buyer duress in late October. An increase in available RA capacity solicitations is consistent with the Track 1 objectives of the Scoping Memo, and will maintain grid reliability while reducing potentially costly backstop procurement. Commission review of RA capacity solicitations and excess volumes in Track 1 would also be beneficial because the availability of RA capacity would inform discussion on RA waivers, which is also scheduled for review in this proceeding.[25]

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23 *See* CCA Parties Comments on the OIR at 4 (October 30, 2017) (for past discussion of this issue).

24 *See, e.g.,* SCE's 2017 Request for Offer Process (begins in July with notification in October) *available at* goo.gl/MPyQgK.

25 Scoping Memo at 7-8.

III. CONCLUSION

The CCA Parties thank the Commission for its consideration of the matters addressed in these comments.

Dated: January 30, 2018

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

LATE-FILED RESPONSE OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO THE MOTION OF COMMERCIAL ENERGY FOR A RULING CLARIFYING THE STANDARDS FOR AGGREGATING CONFIDENTIAL DATA

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

LATE-FILED RESPONSE OF TH CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO THE MOTION OF COMMERCIAL ENERGY FOR A RULING CLARIFYING THE STANDARDS FOR AGGREGATING CONFIDENTIAL DATA

Pursuant to Rule 11.1(e) of the California Public Utilities Commission Rules of Practice and Procedure, the California Community Choice Association (CalCCA) responds to the Motion of Commercial Energy for a Ruling Clarifying the Standards Aggregating Confidential Data.

I. INTRODUCTION

CalCCA supports the Motion of Commercial Energy of California (Commercial Energy), which requests clarification of the guidelines for aggregating confidential data for open, public review by market participants. The requested clarification will benefit all market participants and enable a better public dialogue of the issues raised in this proceeding. In addition, greater clarification will reduce uncertainty in the interpretation of Section 2.A of the proposed Modified Non-Disclosure Agreement (Modified NDA).[1] Finally, addressing this issue through the Motion will expedite discovery by avoiding future discovery disputes.

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1 A proposed Modified NDA was submitted on October 23, 2017, as Exhibit G to the *San Diego Gas & Electric Company (U 902 E) Submission of Joint Report on Results of Meet and Confer Regarding Data Issues*.

II. CLARIFICATION OF CONFIDENTIAL DATA AGGREGATION GUIDELINES WILL BENEFIT MARKET PARTICIPANTS, MODIFIED NDA SIGNATORIES AND THE PUBLIC GENERALLY

Commercial Energy seeks clarification that aggregation of certain confidential hourly volume and price data will render the data non-confidential and available for market participant review.[2] Specifically, it seeks a ruling designating the data non-confidential in one of the three aggregation levels:[3]

1. "[H]istorical data showing hourly volumes and price by contract source," removing "names of the parties to the contract, the location of the generating asset(s), and other information that would allow unmasking of the parties and asset(s)";

2. The aggregated data in 1, aggregating further "into groups of three to five contracts, grouped by like technology and location"; or

3. The aggregated data in 1, aggregating further "by a method other than the proposal in 2."

Commercial Energy requests that if the Commission declines to rule on these specific aggregation forms, that the Commission "clarify the requirements set forth in D.09-12-020 and the IOU Matrix in D.06-06-066 to provide the parties with clear guidance as to how the requirements must be applied to the significant amount and breadth of historical data that will be provided in this proceeding."[4]

Commercial Energy's concern lies with enabling "market participants who are decisionmakers for the parties to this proceeding"[5] to provide meaningful input in this case. While CalCCA appreciates the investor-owned utilities' cooperation in negotiating a Modified NDA permitting certain Community Choice Aggregator (CCA) personnel to

[2] Motion at 1.
[3] *Id.* at 2.
[4] *Id.*
[5] *Id.* at 1.

act as Reviewing Representatives, certain CCA personnel will nevertheless fall into the Market Participant category. In fact, personnel of small CCAs may be precluded entirely from serving as Reviewing Representatives. Commercial Energy's proposal thus will benefit the CCA personnel in this position. The proposal will also enable a broader public dialogue beyond the CCAs and Energy Service Providers (ESPs) to effectively respond to the public allegations made by the IOUs in the context of their recent public affairs campaign.[6]

Beyond the benefits to Market Participants, Commercial Energy's proposal will assist parties in interpreting Section 2.H.1 of the Modified NDA. This section excludes from the definition of "Confidential Information" the following:

> conclusions, summations, aggregations, interpretations or other materials derived from Protected Materials do not themselves constitute Protected Materials so long as all of the following requirements are met: (a) the Requesting Party uses not less than reasonable efforts to adequately mask the detail of the underlying data to prevent disclosure of Protected Information; (b) the masking of the conclusions, summations, aggregations, interpretations or other materials derived from Protected Materials is adequate to prevent disaggregation, unmasking and identification of any Protected Materials; and (c) the measures taken to mask the detail of the underlying data are consistent with Commission decisions regarding the aggregation of data and confidentiality of electric procurement information issued in Rulemaking 05-06-040 and this proceeding.

While Commercial Energy's motion will not entirely settle the meaning of this provision, it will minimize any future delays or discovery disputes for the subject matter it addresses.

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[6] These issues are discussed in the San Diego Gas & Electric Company (U 902 E) Submission of Joint Report on Results of Meet and Confer Regarding Data Issues, filed October 23, at 9-10.

III. CONCLUSION

For all of the foregoing reasons, CalCCA requests that the Commission grant Commercial Energy's motion.

Respectfully submitted,

Evelyn Kahl

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November 13, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

MOTION TO ACCEPT LATE-FILED RESPONSE OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO THE MOTION OF COMMERCIAL ENERGY FOR A RULING CLARIFYING THE STANDARDS FOR AGGREGATING CONFIDENTIAL DATA

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BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	R.17-06-026 (Filed June 29, 2017)

MOTION TO ACCEPT LATE-FILED RESPONSE OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION TO THE MOTION OF COMMERCIAL ENERGY FOR A RULING CLARIFYING THE STANDARDS FOR AGGREGATING CONFIDENTIAL DATA

Pursuant to Rule 11.1 of the California Public Utilities Commission's Rules of Practice and Procedure, the California Community Choice Association (CalCCA) hereby moves the Administrative Law Judge or the Commission to accepts its late-filed "Response of the California Community Choice Association to the Motion of Commercial Energy for a Ruling Clarifying the Standards for Aggregating Confidential Data." Due to an inadvertent oversight by counsel, the response was not filed by the due date. Because there will be no responsive pleadings to CalCCA's Response, no parties' rights would be adversely affected by accepting the late filing. In addition, CalCCA's Response will enhance the record by broadening the Commission's understanding of the scope and impact of Commercial Energy's request.

Respectfully submitted,

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Counsel to the
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November 13, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

JOINT MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SOUTHERN CALIFONRIA EDISON COMPANY (U 338-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E), CENTER FOR ACCESSIBLE TECHNOLOGY, MARIN CLEAN ENERGY, AND CALIFORNIA CHOICE ENERGY AUTHORITY FOR ENTRY OF EXHIBITS INTO EVIDENCE

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

JOINT MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SOUTHERN CALIFONRIA EDISON COMPANY (U 338-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E), CENTER FOR ACCESSIBLE TECHNOLOGY, MARIN CLEAN ENERGY, AND CALIFORNIA CHOICE ENERGY AUTHORITY FOR ENTRY OF EXHIBITS INTO EVIDENCE

In accordance with Rules 1.8(d), 11.1, 13.8(c), and 13.10 of the Commission's Rules of Practice and Procedure, the email ruling of Administrative Law Judge (ALJ) Stephen C. Roscow dated October 6, 2017, as modified by the email ruling of ALJ Roscow dated November 20, 2017, Pacific Gas and Electric Company (PG&E) respectfully submits this Joint Motion on behalf of itself, Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), California Choice Energy Authority (CCEA), Marin Clean Energy (MCE), and Center for Accessible Technology (CforAT) (together, the "Filing Parties") for entry into evidence of certain prepared testimony and discovery responses ("Joint Motion").[1]

Contemporaneous to filing this Motion, pursuant to Rule 1.9(d)(1)-(3) of the Commission's Rules of Practice and Procedure, PG&E has filed a Notice of Availability of this Joint Motion, providing access to all interested parties to an electronic version of the Joint Motion and all of the information described below.[2]

[1] The Filing Parties have collaborated with the following additional parties interested in this proceeding, including the Office of Ratepayer Advocates, The Utility Reform Network, WRCOG, CVAG, and LACCE. These parties support or do not oppose this Motion.
[2] In accordance with Rule 1.8(d), the Filing Parties have authorized PG&E to submit this document on their behalf.

I. PROCEDURAL BACKGROUND

In the September 25, 2017 Scoping Memo and Assigned Commissioner's Ruling for this proceeding, the Commission established Track 1 of this rulemaking to consider the issue of exemption from the Power Charge Indifference Adjustment (PCIA) for customers using California Alternative Rates for Energy (CARE) and Medical Baseline (MB) rates and defined the scope of Track 1 as "review and possible revision of exemptions and the consistency of treatment of exemptions between SCE, PG&E, and SDG&E."[3] By email to ALJ Roscow dated October 6, 2017, the Filing Parties supported and requested approval to import testimony and responses to discovery from other proceedings on the proposals regarding the appropriate treatment of PCIA exemptions for CARE and MB customers. The Filing Parties also supported conducting additional discovery and moving appropriate discovery responses into the record for this proceeding by Joint Motion. ALJ Roscow approved this procedural path by email ruling dated October 6, 2017. Subsequently, the Filing Parties requested, and in an email ruling dated November 30, 2017, ALJ Roscow approved, an extension to December 5, 2017 to submit this Joint Motion.

The parties have continued to meet-and-confer about the appropriate procedural path forward to resolve Track 1 of this proceeding. After discussing several alternatives, the parties reached consensus that the evidentiary record for Track 1 should consist of the following: (1) SCE's and PG&E's previously-submitted testimony in, respectively, SCE's 2016 RDW and PG&E's 2014 GRC Phase 2, regarding Track 1 issues (i.e., the CARE and MB PCIA exemptions); (2) all exchanged and pending data request responses as of today's date in this proceeding regarding Track 1 issues; and (3) an opportunity for non-utility parties to submit responsive testimony on Track 1 issues. In addition, although the parties currently

[3] Scoping Memo and Ruling of Assigned Commissioner, pp. 16-17.

do not believe that evidentiary hearings will be necessary, the parties reserve their rights to request them. If evidentiary hearings do occur, they would also be part of the evidentiary record.

To facilitate this consensus procedural path, the parties propose the following new Track 1 deadlines:

1/5/18	Non-utility party responsive testimony
1/10/18	Parties inform the ALJs whether or not they believe evidentiary hearings are necessary
1/23/18	Concurrent Opening Briefs (assuming evidentiary hearings are not held)
2/23/18	Concurrent Reply Briefs (assuming evidentiary hearings are not held)

In the event that evidentiary hearings are held, the proposed briefing schedule may need to be extended. Finally, the parties have initiated settlement discussions and will keep the ALJs appropriately apprised of the status of those discussions going forward.

II. MOTION FOR ENTRY OF EVIDENCE INTO THE WRITTEN RECORD

Pursuant to Rule 13.8(c), the Track 1 Parties respectfully move that the following information be admitted into evidence:

Exhibit 1	Updated and Amended Prepared Testimony in PG&E's 2017 General Rate Case Phase II, A.16-06-013, Exhibit PG&E-8, Volume 1, Revenue Allocation and Rate Design, served December 2, 2016, pages 1-16 to 1-18 and Attachment C
Exhibit 2	PG&E's Public/Non-Confidential Responses to Data Requests in PG&E's 2017 General Rate Case Phase II, A.16-06-003

Exhibit 3	PG&E's Public/Non-Confidential Responses to CforAT Data Requests 001 and 002 in PCIA OIR, R.17-06-026
Exhibit 4	PG&E's Responses to MCE Data Requests 001, 002 and 003 in PCIA OIR, R.17-06-026
Exhibit 5	CforAT Responses to PG&E Data Request 001 in PCIA OIR, R.17-06-026
Exhibit 6	MCE Responses to PG&E Data Request 001 in PCIA OIR, R.17-06-026
Exhibit 7	Testimony of Southern California Edison Company In Support of Its Application for Approval of Its 2016 Rate Design Window, A.16-09-003, Exhibit SCE-1, served September 1, 2016, at pp. 116-132.
Exhibit 8	SCE Responses to CCEA Data Requests 003, 003 (Supplemental), and 004 in PCIA OIR, R.17-06-026
Exhibit 9	SCE Responses to CforAT Data Request 001 in PCIA OIR, R.17-06-026
Exhibit 10	CCEA Responses to SCE Data Requests 001 and 002 in PCIA OIR, R.17-06-026

Respectfully submitted on behalf of the Filing Parties,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2018 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation. (U39E)	Application 17-06-005 (Filed June 1, 2017)

MARIN CLEAN ENERGY, PENINSULA CLEAN ENERGY AUTHORITY AND SILICON VALLEY CLEAN ENERGY AUTHORITY RESPONSE TO PG&E MOTION TO OFFER THE NOVEMBER UPDATE INTO EVIDENCE AND ADMIT THE NOVEMBER UPDATE INTO THE RECORD UNDER RULE 13.8(C)

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2018 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation. (U39E)	Application 17-06-005 (Filed June 1, 2017)

MARIN CLEAN ENERGY, PENINSULA CLEAN ENERGY AUTHORITY AND SILICON VALLEY CLEAN ENERGY AUTHORITY
RESPONSE TO PG&E MOTION
TO OFFER THE NOVEMBER UPDATE INTO EVIDENCE AND ADMIT THE NOVEMBER UPDATE INTO THE RECORD UNDER RULE 13.8(C)

Pursuant to Rule 11.1(e) of the Commission's Rules of Practice and Procedure, Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority and Silicon Valley Clean Energy Authority (the "Joint CCAs") hereby respond to Pacific Gas & Electric Company's ("PG&E") Motion to Offer the November Update into Evidence and Admit the November Update into the Record under Rule 13.8(C) (the "Motion"). The Joint CCAs do not oppose the Motion, but wish to draw the Commission's attention to the insufficiency of the "DOE Adder" component of the "Green Adder" used to compute the Market Price Benchmark ("MPB") included in the November Update and call on the Commission to order that the DOE data source should no longer be used for future Energy Resource Recovery Account ("ERRA") proceedings and establish a process for resolving this issue in the future.

I. Background on Market Price Benchmark Formula

In D.11-12-018, the Commission revised the methodology for the Market Price Benchmark used to calculate customer cost responsibility necessary to maintain bundled customer indifference. The MPB is "a calculated proxy which represents the market value of the IOU total energy resource portfolio."[1] The Market Price Benchmark is subtracted from the three large investor-owned utilities' ("IOU") total portfolio costs to calculate the Power Charge Indifference Amount.[2] If the indifference amount is positive, this demonstrates that the IOU's portfolio cost was above-market in that year, and this amount is recovered from departed load through a non-bypassable surcharge.[3]

The Commission incorporated into the Market Price Benchmark an adder to reflect the market value of Renewables Portfolio Standard ("RPS") resources based on the price premium associated with the IOUs' renewable portfolio (the "Green Adder").[4] One component of the Green Adder is based on the costs of the IOUs' owned or contracted RPS resources (the "IOU RPS Adder").[5] This premium was then to be weighted by the percentage of California load subject to RPS requirements served by the IOUs.[6]

A second component of this adder was intended to reflect the renewable premium of the portfolio of non-IOU load-serving entities ("LSEs") in California.[7] Specifically, the Commission ordered the IOUs to file advice letters providing the "most recent 12 months figures derived from US Department of Energy survey of Western US renewable energy premiums in calculating a

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1 Decision ("D.")11-12-018 Decision Adopting Direct Access Reforms (December 1, 2011) at 8.

2 *Id.*; *see also* Resolution E-4475 at 2.

3 D.11-12-018 at 9.

4 *Id*. at 17, Ordering Paragraphs 2, 4.

5 *Id*. at 22, Ordering Paragraph 5.

6 *Id*.

7 *Id*. at 18, 22-23.

weighted proxy for the Market Price Benchmark compiled by the National Renewable Energy Laboratory" (the "DOE Data").[8] This proxy value (the "DOE Adder") is then to be weighted according to the percentage of California load subject to RPS requirements served by non-IOUs.[9]

The Commission adopted the data inputs contained in the advice letter filings ordered in D.11-12-018 and a formula to compute the MPB in Resolution E-4475.[10] The Commission ordered the IOUs to file Tier 1 advice letters by October 1 of each year thereafter "to update the data specified in Ordering Paragraph 4 of Decision 11-12-018 and shown in the Background Section of this Resolution, so that the applicable percentage weightings are updated in subsequent years."[11] As Resolution E-4475 explained, the Green Adder is then used to compute the MPB in each IOU's annual ERRA application.[12]

II. Procedural Background

A. PG&E's Use of 2015 DOE Data this Application

In this Application, PG&E's Green Adder calculation utilized a "DOE REC value" of $16.64/MWh,[13] which was the DOE Adder value approved by the Energy Division in response to PG&E's Advice Letter 4927-E in 2016 for the 2017 DOE Adder.[14] The Joint CCAs protested this Application in part on the ground that the data used to compute the Green Adder was not

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8 *Id.*, Ordering Paragraph 4(a) (emphasis added).

9 *Id.* at 22-23; Ordering Paragraph 5.

10 Resolution E-4475, Ordering Paragraphs 1, 3, Exhibit A.

11 *Id.*, Ordering Paragraph 4.

12 *Id.* at 8; *see also* D.11-12-018 at 8.

13 Pacific Gas and Electric Company Prepared Testimony 2018 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation, Chapter 9, Table 9-5.

14 *See* PG&E Advice Letter 4927-E, Appendix A.

transparent and was incorrect.[15] In the Joint CCAs' testimony, Dr. Richard McCann pointed out that the url for the NREL website purportedly leading to the DOE Data to which PG&E referred in its workpapers[16] did not actually lead to this data source.[17] In addition, Dr. McCann demonstrated that the set of renewable premiums for the western region compiled by DOE was last updated in 2015 and contained numerous inaccuracies, including reference to utilities no longer in operation, incorrect renewable premium data and references to the IOUs' renewable tariffs, which are not meant to be counted in the non-IOU LSE portion of the Green Adder.[18]

PG&E has admitted that the data on the National Renewable Energy Laboratory ("NREL") website are no longer current and that the website it had accessed to obtain these data in 2016 is no longer available:

> PG&E acknowledges that certain data that was on the NREL website, which was maintained by NREL and simply accessed by PG&E and the other IOUs annually for purposes of the October 1 Tier 1 advice letter filing, may not be current. Moreover, it appears as though the NREL website accessed by PG&E for its October 1, 2016 Tier 1 advice letter filing is no longer available. For these reasons, PG&E does not disagree with SCP that the use of the DOE Green Adder is problematic.[19]

B. PG&E's Advice Letter 5151-E

PG&E filed Advice Letter 5151-E (the "Advice Letter") pursuant to Resolution E-4475 on October 2, 2017. PG&E stated that, with respect to the DOE Data, the "last available

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15 Protest of Marin Clean Energy, Peninsula Clean Energy Authority, The Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority to PG&E's Energy Resource Recovery Account Application (July 7, 2017) ("Protest") at 7.

16 *See* Exhibit PGE-03, PG&E workpaper tab Green Adder – Appendix A - 2017 (citing http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=1). At this time, this url only leads to an error message. Last visited November 16, 2017.

17 Testimony of Richard J. McCann, Ph.D. on Behalf of Sonoma Clean Power Authority (Revised) (August 28, 2017) ("McCann Testimony") at 11; *see also* Opening Brief of Marin Clean Energy, Peninsula Clean Energy, Silicon Valley Clean Energy, and Sonoma Clean Power Authority in PG&E's Energy Resource Recovery Account Application (Oct. 2, 2017) ("Joint CCAs Opening Brief") at 19-20.

18 McCann Testimony at 11-13.

19 Opening Brief of Pacific Gas and Electric Company (U 39 E) (Oct. 2, 2017) at 22.

published data set that PG&E is aware of is what was presented in [sic] year's advice letter, which at the time was published in September 2016 and this is presented again in this year's Appendix A. That value was $16.64 per MWh."[20] PG&E also provided an "independently verified" list of the voluntary green pricing programs that had previously been compiled by NREL in response to the Joint CCAs' criticism that the DOE Data used to calculate the 2017 Green Adder were unsourced and had outdated information.[21]

The Joint CCAs protested Advice Letter 5151-E on October 23, 2017, on the grounds that the Advice Letter did not (and could not) comply with Ordering Paragraph 4(a) of D.11-12-018 because the DOE Data were no longer available, and because the use of PG&E's proposed "independently verified" alternative figure was not appropriate to an advice letter process.[22] Instead, we reasoned that this proceeding was the proper venue to address these issues.[23] PG&E and SCE filed a joint reply to the Joint CCAs Advice Letter Protest on October 30, 2017.

On November 1, 2017, the Energy Division issued a disposition letter approving the Advice Letter.[24] The Energy Division correctly rejected PG&E's proposed use of its own "independently verified" renewable contract premium on the ground that these calculations were

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20 PG&E Advice Letter 5151-E at 2.

21 *Id*.

22 Protest of the Joint CCA Parties to Pacific Gas and Electric Company's Advice Letter 5151-E and Southern California Edison Company's Advice Letter 3667-E (October 23, 2017) ("Joint CCAs Advice Letter Protest").

23 *Id*. at 3 (citing D.08-09-012 at 69 ("[I]ssues regarding consistency of the implementation and calculation of the CRSs with respect to this decision can be raised and litigated in the forecast phase of the IOUs' ERRA proceedings."); D.11-12-018 at 8 ("The indifference amount is updated annually in each IOU's Energy Resource Recovery Account (ERRA) proceeding.")).

24 Letter to Erik Jacobsen, Director, Regulatory Relations, PG&E from Edward Randolph, Director, Energy Division, California Public Utilities Commission (November 1, 2017) ("Disposition Letter"), *available at*: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5151-E.pdf.

inconsistent with Resolution E-4475.[25] The Energy Division approved of the use of the 2015 DOE Data in the Disposition Letter because it was the last updated data available on the NREL website.[26]

C. PG&E's November Update and Motion

On November 2, 2017, PG&E served its November Update.[27] The November Update uses the 2015 DOE Data for the non-IOU component of the Green Adder.[28] On the same day, PG&E filed the Motion.

III. The DOE Data Used to Calculate the MPB is Outdated, Incorrect and Flawed, and the MPB Should Be Revised in the Future.

As the Joint CCAs raised in their Protest to this Application and testimony, the DOE Data source is deeply flawed because it contains green premium information from numerous tariffs that no longer exist, contains inaccurate green premium information for some existing tariffs, and does not contain figures from "the most recent 12 months."[29] First, the url for the DOE Data source cited by PG&E in Advice Letter 5151-E currently returns an error message so it cannot be verified.[30] In fact, correspondence between Dr. McCann and personnel at NREL indicates that this data may not have been publicly available for years.[31] Second, as the Energy Division found,

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25 Disposition Letter at 2.
26 Disposition Letter at 1.
27 Pacific Gas and Electric Company 2018 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation Update To Prepared Testimony (November 2, 2017) ("PG&E November Update").
28 *Id*. at 6.
29 McCann Testimony at 11-13; Joint CCAs Opening Brief at 19-20.
30 Advice Letter 5151-E, Appendix A, note 1 (citing http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=1), last visited November 16, 2017.
31 McCann Testimony at 11.

these data were last updated in May of 2015.[32] Third, many of the green tariffs contained in this data source are no longer in existence, or contain inaccurate pricing information.[33]

Moreover, the DOE Data are highly problematic because they include green tariffs of varying percentages of clean energy, whereas the IOU RPS Adder is based on RPS-eligible resources and, therefore, is 100% clean energy. For example, the list of tariffs included in Appendix A to PG&E's workpapers includes MCE's Light Green (50% renewable), Deep Green (100% renewable), Local Sol (100% local solar); Sonoma Clean Power's ("SCP") Clean Start (incorrectly listed as 36% biomass, geothermal and wind)[34] and Evergreen (100% geothermal); and NV Energy's NV Green Energy Rate ("50% or 100% renewables").[35] Other tariffs do not list the percentage of green power. Further, the table lists MCE's Light Green and SCP's Clean Start premium as zero (0) cents per kilowatt-hour, and other tariffs are listed as "varies by utility" or "contribution" and are ignored in the calculation. These discrepancies undercount the market value of non-IOU LSE RPS energy because the green premiums are not reflective of the actual market value of 100% green energy compared to the same "brown" power baseline used for the IOU RPS premium. This problem results in overcounting the IOUs' above-market costs and establishing an improperly high PCIA.

Further, the inclusion of two of MCE's and SCP's green tariffs with a zero premium illustrates a further problem endemic to all of the green tariffs used to calculate the average non-IOU LSE green premium. MCE's and SCP's base portfolio costs are already inflated by green power purchases compared to the "brown" power metric used for the IOU's RPS premium

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32 Disposition Letter at 1.

33 McCann Testimony at 12-13; Joint CCAs Opening Brief at 19-20.

34 The correct amount is 42% renewable according to SCP's website, available at https://sonomacleanpower.org/your-options/new-cleanstart/ (last visited November 16, 2017).

35 Exhibit PGE-03, PG&E workpaper tab Green Adder – Appendix A – 2017.

calculation. MCE's base portfolio already exceeds PG&E's base portfolio and the RPS target for 2020.[36] As a result, the rate premiums for MCE's green rate programs are severely underestimated relative to the brown power MPB used to determine the IOU's RPS premium. This miscalculation exists throughout the entire database—virtually every utility in the Western Electric Coordinating Council ("WECC") region has significant renewable power resources in their portfolios. This discrepancy has the effect of suppressing the green premium associated with non-IOU WECC renewable energy, decreasing the MPB and thereby leading to an improperly high PCIA.

Further, the database does not include a number of commercial and industrial class green power tariffs. For example, a recent article in Utility Dive describes such tariffs offered by Puget Sound Energy, and Xcel (Colorado) that are not listed in the database.[37] Without a significant effort to survey the entire WECC, it is not possible to have confidence in whether either the original or updated databases are complete or accurate.

For these reasons, the DOE Adder should not be used to calculate the MPB going forward. While we recognize the need to proceed on an expeditious basis to revise the 2018 MPB, and therefore do not oppose the Motion, we ask that the Commission in its Decision in this docket make a finding regarding the inadequacy of the DOE Adder, and set forth a plan for correcting this problem in the future. For example, the Commission could set a Track 2 of this

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36 *Compare* https://www.mcecleanenergy.org/your-energy-choices/ (explaining that MCE's Light Green product with 50% renewable content is the default for its customers) (last visited November 16, 2017) *with* https://www.pge.com/en_US/about-pge/environment/what-we-are-doing/clean-energy-solutions/clean-energy-solutions.page (stating that 33% of PG&E's portfolio is comprised of eligible renewable resources) (last visited November 16, 2017).

37 "Utility success with corporate renewables demand raises questions for existing load," *Utility Dive* (October 5, 2017), *available at*: https://www.utilitydive.com/news/utility-success-with-corporate-renewables-demand-raises-questions-for-exist/506220/ (last visited Nov. 16, 2017).

docket that includes the other IOUs, as the Commission has previously done, to address this issue so that it can be resolved for the 2019 ERRA forecasting applications. In addition, the Commission should order that the DOE data source will no longer be used as a metric for calculating any component of the PCIA. Doing so will not only guide the 2019 ERRA forecasting proceedings but also help ensure the current methodology for calculating the MPB will not be included in a revised PCIA or new non-bypassable charge, if such rate mechanisms are adopted in the PCIA OIR (R.17-06-026).

IV. Conclusion

The Joint CCAs recognize that the DOE website and data are beyond the control of the Commission and the IOUs, and also recognize the time constraints associated with the ERRA forecasting docket. In light of this, we recommend that the Commission make an explicit finding regarding the inadequacies of the DOE Data based on the issues highlighted herein, order that the DOE data source will no longer be used as a component to calculate the PCIA, and order a process for resolving this issue for future ERRA forecasting dockets.

Respectfully submitted ,

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November 17, 2017

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

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2018 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation. (U39E)	Application 17-06-005 (Filed June 1, 2017)

COMMENTS ON PROPOSED DECISION OF MARIN CLEAN ENERGY, PENINSULA CLEAN ENERGY AUTHORITY AND SONOMA CLEAN POWER AUTHORITY

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January 2, 2018

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2018 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation. (U39E)	Application 17-06-005 (Filed June 1, 2017)

COMMENTS ON PROPOSED DECISION OF MARIN CLEAN ENERGY, PENINSULA CLEAN ENERGY AUTHORITY AND SONOMA CLEAN POWER AUTHORITY

Pursuant to Rule 14.3(a) of the Commission's Rules of Practice and Procedure, Marin Clean Energy ("MCE"), Peninsula Clean Energy Authority and Sonoma Clean Power Authority (the "Joint CCAs") submit these comments on the Proposed Decision of Administrative Law Judge Tsen Adopting Pacific Gas and Electric Company's 2018 Energy Resource Recovery Account Forecast and Generation Non-Bypassable Charges and Greenhouse Gas Forecast Revenue and Reconciliation (the "Proposed Decision"). The Joint CCAs submit that the Proposed Decision errs on a legal basis by adopting Pacific Gas and Electric Company's ("PG&E") Power Charge Indifference Adjustment ("PCIA") forecast for 2018 because the evidence provided by PG&E fails to satisfy the requirements under sections 451, 454(a) and 366.2(f)(2) of the Public Utilities Code. In addition, the Proposed Decision should be revised to expressly find that the "DOE Adder" component of the Market Price Benchmark ("MPB") used to calculate the PCIA is erroneous, noncompliant with past Commission decisions, and should not be used going forward in the future to calculate the PCIA. Finally, the Proposed Decision errs in providing inconsistencies with regard to the effective date for rate changes and should be revised to take into account the need for additional evidence and cross-examination thereof, timing of PG&E's Tier 1 advice letter, and consistency with the Annual Electric True-Up ("AET") implementation timing and direct that PCIA and other PG&E revenue requirements be recovered over the same time period.

I. The Proposed Decision Errs in Adopting PG&E's 2018 PCIA Forecast Because the Evidence Fails to Meet the Statutory Requirements for an Increase in the Power Charge Indifference Adjustment Rates.

PG&E's request to increase its Power Charge Indifference Adjustment ("PCIA") rates is subject to two statutory requirements under the Public Utilities Code: (1) the PCIA rate must be "just and reasonable";[1] and (2) a change in the PCIA rate cannot be made "except upon a showing before the commission *and a finding by the commission* that the new rate is justified."[2] The request to increase PCIA rates is also constrained by Public Utilities Code section 366.2(f)(2), which only allows PG&E to recover its "net *unavoidable* electricity purchase contract costs attributable to [a CCA] customer" (emphasis added). All costs that PG&E could have avoided are not legally recoverable as a part of the PCIA. The Joint CCAs contend that the Commission cannot find on the basis of the evidence submitted by PG&E that these requirements have been met, and thus the Proposed Decision contains legal error.

The Proposed Decision does not fully address the Joint CCAs' argument about the quality of the evidence presented by PG&E in support of its application. Our argument isn't merely about the appropriate evidentiary standard to be applied.[3] Instead, we have argued that the Commission cannot make its required finding that the PCIA rates being requested are "reasonable," "just," and "justified" based on the evidence presented by PG&E, for three reasons: (1) neither the Joint CCAs nor other parties have had the opportunity to cross-examine PG&E with respect to the new evidence it submitted on November 2, December 6 and December 11, 2017 (2) PG&E's evidence is insufficiently transparent to permit the Commission to make these required statutory findings, and (3) PG&E seeks to recover avoidable costs in violation of Section 366.2(f)(2).

A. Impacted Parties Have Not Had the Opportunity to Cross-Examine PG&E with Respect to New Evidence It Has Submitted.

In addition to the testimony and workpapers submitted by PG&E with its original application in June 2017, PG&E submitted two additional sets of testimony and workpapers on November 2 and December 6, 2017, and filed motions to introduce each new batch of evidence into the record. PG&E also updated its December 6th testimony with a correction on December 11, 2017, and filed a motion for admission of this third evidentiary submission. The Sonoma Clean Power Authority ("SCPA") contested these motions and objected to the introduction of the new evidence, because the evidence did not merely *update* the originally submitted evidence, but rather contained entirely new evidentiary elements to address "gaps" in the original evidence brought to light by the Joint CCA Parties at the evidentiary hearing.

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1 Cal. Pub. Util. Code § 451.
2 Cal. Pub. Util. Code § 454(a) (emphasis added).
3 *See* Proposed Decision at 9.

For example, on September 28, 2017, Laura Hudson, Expert Case Manager Regulatory Affairs at PG&E emailed Steve Shupe, General Counsel for SCPA and Richard McCann, the Joint CCAs' expert witness, acknowledging that PG&E's workpapers that support Chapter 14 (Rates), did not include the "allocation and rates portion of information" associated with the calculation of the PCIA.[4] Ms. Hudson attached an additional workpaper that purported to demonstrate how the PCIA revenue allocation and rate design is conducted.[5] To date, neither the Joint CCAs nor any other party have had the opportunity to cross-examine PG&E's witnesses with respect to this new data.

SCPA also noted that the testimony included in PG&E's November 2 update included significant changes to assumptions regarding Community Choice Aggregator ("CCA") load departure that resulted in a 14% increase in the PCIA revenue requirement.[6] Because of these entirely new areas, SCPA claimed in its opposition to the PG&E motions that it should be given an additional right to cross-examine PG&E witnesses about these new areas.[7]

It would be a violation of the Joint CCA Parties' due process rights if the testimony were admitted without affording a right of cross-examination. Moreover, this would violate Public Utilities Code section 454(d), which grants public utility customers affected by a proposed rate change the right to testify regarding such change. Thus, on the basis of the record before the Commission at this time, the Commission cannot set the PCIA rates based upon the November 2, December 6, or December 11 submissions because the Joint CCA Parties have not been given a right to cross-examine and testify with respect to these new submissions.

B. The Change to PG&E's PCIA Fails to Meet the "Just and Reasonable" Standard and the Commission Cannot Reasonably Find that it is Justified.

Second, the complexity and opacity of PG&E's PCIA calculations makes it impossible for the Commission to make the required statutory findings that the PCIA rates proposed are "just," "reasonable," and "justified." For example, Chapter 9 of PG&E's testimony presented no evidence or

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4 Opposition of Sonoma Clean Power Authority to Motion of Pacific Gas and Electric Company to Offer the November Update into Evidence and Admit the November Update into the Record Under Rule 13.8(C) (November 17, 2017) ("SCPA Opposition to PG&E November 2nd Motion") at 3, attachment ("Laura Hudson Email").

5 *Id*.

6 SCPA Opposition to PG&E November 2nd Motion at 4-5.

7 *Id*. at 3-4; Opposition of Sonoma Clean Power Authority to Motion of Pacific Gas and Electric Company to Offer the "Conforming Corrected" November Update into Evidence and Admit the November Update into the Record Under Rule 13.8(C) (December 18, 2017).

supporting calculations for how the total PCIA revenue requirement is attributed to departed load customers. Table 9-4 shows the calculation of the PCIA revenue requirement *in total* (i.e. ranging from approximately $1.87 billion to $2.26 billion by vintage) but fails to allocate those amounts among bundled and the various classes of departed customers.[8] The PCIA revenue requirement attributable to those classes of departed customers are not calculated anywhere in the Chapter 9 workpapers, even though Table 9-2 shows the PCIA revenue requirement of $642.4 million for departed customers.[9] Chapter 9 does not have a direct reference to Chapter 14, and the calculation for the revenue requirements contained in the Chapter 14 workpapers was only revealed by PG&E in response to a data request.[10] Neither Chapter 14 nor its workpapers contain any direct calculations that can be readily verified for the PCIA revenue requirement attributable to departed customers because there is no reference to the billing determinant forecast by vintage and rate schedule which is at the core of the calculation.[11] In addition, neither Chapter 9 nor the supporting workpapers provide any calculations or data for allocating the revenue requirements to individual CCAs.

In addition, as demonstrated by the Joint CCAs through cross-examination and as explained in their opening brief, PG&E's explanation of the derivation of this rate was circular: PG&E witness Donna Barry explained that PCIA rates are multiplied by expected departed load sales to generate the PCIA revenue requirement, while it's witness Robert Bremault stated that the PCIA revenue requirement is used to develop PCIA rates.[12] While PG&E replied that the two witnesses were referring to the data output of different stages of the PCIA rate calculation process when they both referred to the "PCIA revenue requirement,"[13] PG&E still has not clearly described to which stages of the PCIA revenue requirement each witness was referring, making it impossible for other parties and the Commission to understand and vet its PCIA calculation process.[14] On September 28, 2017, after the

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8 *See* PG&E Conforming Corrected Update to Prepared Testimony (December 6, 2017, corrected December 11, 2017), Table 9-4.

9 *Id.*, Table 9-2.

10 PG&E Data Response SCP_005-Q02 (August 23, 2017), attached hereto as Exhibit 1.

11 *See* "Res BD, PRs, and Revenues Table.xlsm," worksheet in_PCIA_Present_BDS, column K, which contains only numbers with no formulas or linked values, and no references to sources of the data. "Ag and C&I BD, PRs, and Revenues Table.xlsm" contains the same worksheet. None of the Chapter 2 workpapers, which document the sales forecast, contain the vintaged billing determinants data. As noted below, the Joint CCA Parties received the complete workpapers after closure of the evidentiary record and have not had an opportunity for further cross-examination with respect to these models.

12 Joint CCAs Opening Brief at 6-7.

13 PG&E Reply Brief at 7.

14 *See, e.g.*, Transcript 40:24 – 47:11.

conclusion of the evidentiary hearings and the same day as submittal of the initial brief in this proceeding, PG&E provided the spreadsheet that linked the Chapter 9 PCIA revenue requirements to the Chapter 14 calculations.[15] As a result of this delay, the Joint CCA Parties have not had an opportunity for in-depth discovery and presentation of evidence on whether the calculations in those workpapers are accurate or thorough. The Joint CCAs assert that PG&E provided insufficient evidence to support the final revenue requirement request and therefore the application should be denied.

The Proposed Decision disregards the Joint CCA Parties' concerns about the opacity and complexity of the PCIA rate calculations by reasoning that the Joint CCA Parties "did not allege incorrect calculations of the PCIA."[16] Our point, however, is that it is impossible for the Commission or affected customers or the organizations who represent them to understand these calculations and determine whether or not there are incorrect calculations because the derivation of the rates is not transparent. Ultimately, it is not the Joint CCA Parties' burden to show that the PCIA rates are wrong, it is PG&E's – and the Commission's – burden to show that they are right.[17] More importantly, the Commission has the duty under Public Utilities Code sections 451 and 454 of assuring the customers of PG&E and the Joint CCA Parties who will be paying the new PCIA rates – totaling nearly six hundred thirty-two million dollars ($632,000,000) -- that those rates are "just," "reasonable," and "justified."[18]

The Proposed Decision notes that a summary of PG&E's PCIA calculations were presented using standard summary formats required by Decision 17-08-026. As D.17-08-026 noted, however, the purpose of requiring the standard format was to "facilitate the analysis and comparison of PCIA calculations across utilities."[19] The standard formats present the results of the PCIA rate calculation at a very high level, and do not show all of the steps by which the specific PCIA rates were calculated. Putting summary figures into the required standard format does not make the figures correct, or immunize them from challenge.

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[15] Laura Hudson Email.

[16] Proposed Decision at 10.

[17] *See, e.g.* Decision 16-06-056 at 21 ("The Commission requires that the public utility demonstrate with admissible evidence that the costs which it seeks to include in revenue requirement are reasonable and prudent. The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable").

[18] *Id*. at 166-67 (affirming that utility bears the burden of showing that its forecasts are just and reasonable and that Commission must consider all evidence to determine whether rates are just and reasonable).

[19] D.17-08-026, Finding of Fact 3.

Unless the Commission can understand and explain how the individual PCIA rates being proposed by PG&E were calculated, then the Joint CCA Parties submit that the Commission cannot properly make the findings required by sections 451 and 454.[20] PG&E's PCIA calculations may be right, or they may be wrong, and neither the Joint CCA Parties nor the Commission knows which is true. Given that state of affairs, the Joint CCA Parties contend that the application must be denied.

C. The Proposed Decision Errs by Permitting PG&E to Recover Avoidable Electricity Purchase Costs.

There is a third basis for rejecting PG&E's proposed change to the PCIA. As noted earlier, Public Utilities Code section 366.2(f)(2) only allows PG&E to recover its "net *unavoidable* electricity purchase contract costs attributable to [a CCA] customer." In our Protest to PG&E's application and original testimony submitted for the evidentiary hearing, the Joint CCAs argued that a portion of the costs PG&E was seeking to recover in its application were "avoidable" costs, and that allowing PG&E to recover them in 2018 PCIA rates would directly violate Section 366.2(f)(2).[21]

Specifically, the Joint CCA Parties argued that for CCAs that had departed PG&E service in years past (Marin Clean Energy, SCPA, and Clean Power SF), PG&E's failure to divest itself of unneeded generation resources at the time those loads departed had resulted in a more-expensive-than-necessary portfolio.[22] This more-expensive-than-necessary portion of PG&E's portfolio costs was avoidable, and charging CCA customers for it was thus illegal under section 366.2(f)(2).

The Administrative Law Judge refused to allow the Joint CCA Parties to pursue this argument in this proceeding, adopting PG&E's position that such an argument could only be made as a part of the next ERRA compliance proceeding.[23] The Joint CCAs' arguments on this point are not addressed in the Proposed Decision. This was error. Section 366.2(f)(2) could not be clearer: CCA customers may not be charged any "avoidable" costs. Allowing PG&E to charge CCA customers for "avoidable" costs for

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20 *See* Decision 16-06-056 at 166-67.

21 Protest of Marin Clean Energy, Peninsula Clean Energy Authority, the Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority to PG&Es Energy Resource Recovery Account Application (July 7, 2017) ("Joint CCAs Protest") at 2-6.

22 *Id*. at 4-6.

23 Scoping Memo and Ruling of Assigned Commissioner (August 4, 2017) at 3-4. ("[T]he joint CCAs and San Francisco raised PCIA related issues that are outside the scope of a single utility ERRA forecast proceeding. The Joint CCAs argue that avoidable electric contract purchase prices should not be recovered in the PCIA. … PG&E's administration of procurement contracts, as well as its management of procurement portfolios are outside the scope of an ERRA forecast proceeding and best addressed in the compliance phase.").

2018 would violate the section. Granting PG&E's application would thus violate California law.[24] Further, because there is no mechanism to true up the PCIA through a balancing account, merely addressing this issue in the ERRA compliance proceeding would not remedy the harm to departed load customers.

To conclude, the Commission cannot make the required findings that PG&E's requested 2018 PCIA rates are "reasonable," "just," and "justified." Moreover, the PCIA rates allow for recovery of "avoidable" costs in violation of Public Utilities Code 366.2(f)(2). For both these reasons, the Proposed Decision contains legal errors. The Commission should return this matter to the Administrative Law Judge for further evidentiary hearings.

II. The Proposed Decision Errs by Approving PG&E's Inclusion of Fuel and Variable Costs Associated with Dispatchable Generation Resources in the PCIA.

In our opening brief, the Joint CCAs argued that fuel and other variable costs associated with dispatchable resources used to serve PG&E's bundled load should be excluded from the PCIA because these are load-driven.[25] This argument was supported by D.11-12-018, which ordered the exclusion of all load-driven CAISO costs from the PCIA.[26] In D.11-12-018, the Commission reasoned that departed customers should not have to pay twice for CAISO costs (once through their retail provider and once through bundled service customers' CAISO costs through the PCIA).[27]

In finding that it was appropriate for PG&E to include fuel and variable costs associated with dispatchable generation resources within its PCIA calculation, the Proposed Decision misses the analogy between the CAISO market transactions and PG&E's other load-driven costs. The Proposed Decision reasons that

> these resources are dispatched by CAISO and PG&E has no discretion in whether to schedule and bid the resources into the market in compliance with the Commissions Standard of Conduct 4 for least cost dispatch. The dispatchable resources were procured to serve PG&E's load as

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24 Nor is it clear that any mechanism exists that would allow CCA customers to recover in the 2019 ERRA Compliance proceeding any "unavoidable" costs charged to CCA customers through the PCIA during 2018. Unlike the ERRA account for PG&E's bundled customers, there is no balancing account for the PCIA. It is uncertain how illegal "avoidable cost" PCIA overcollections in 2018 would be refunded to CCA customers.

25 Joint CCAs Opening Brief at 8-18.

26 D.11-12-018, Ordering Paragraph 6; *see also id*. at 32, reasoning that costs that "var[y] directly with the load served" should be excluded.

27 *Id*. at 31-32.

forecasted at the time of procurement, and PG&E is required to bid those resources into the market even though loads have departed.[28]

The key issue is not who has control of PG&E's dispatchable generation, but rather what is the driving factor for the *level* of PG&E's generation. What does determine the amount of generation dispatched is the level of load. All things being equal, when load increases, demand increases, and this increases the price of power. This price factors in to the calculation of whether PG&E's dispatchable resources are "in the money" and must be dispatched per Standard of Conduct # 4. The Proposed Decision therefore erred in failing to exclude the fuel and variable costs associated with PG&E's dispatchable resources because they load-based CAISO charges that must be excluded per D.11-12-018.

III. The Proposed Decision Should Be Revised to Find that the DOE Data Used to Calculate the Market Price Benchmark Component of the PCIA is Outdated, Incorrect and Flawed, and Should Not Be Used in the Future.

As the Joint CCAs raised in their Protest to this Application and testimony, the U.S. Department of Energy ("DOE") data source required by D.11-12-018 to be used to calculate the "DOE Adder" component of the MPB is deeply flawed because it contains green premium information from numerous tariffs that no longer exist, contains inaccurate green premium information for some existing tariffs, and does not contain figures from "the most recent 12 months" as is required by D.11-12-018.[29] In the Joint CCAs' testimony, Dr. Richard McCann pointed out that the url for the NREL website purportedly leading to the DOE Data to which PG&E referred in its workpapers[30] did not actually lead to this data source and currently returns an error message so it cannot be verified.[31]

PG&E has admitted that the data on the National Renewable Energy Laboratory ("NREL") website are no longer current and that the website it had accessed to obtain these data in 2016 is no longer available.[32] The Energy Division found that these data were last updated in May of 2015.[33]

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28 Proposed Decision at 11-12.

29 D.11-12-018, Ordering Paragraph 4(a); Joint CCAs Protest at 7; Testimony of Richard J. McCann, Ph.D. on Behalf of Sonoma Clean Power Authority (Revised) (August 28, 2017) ("McCann Testimony") at 11-13; Joint CCAs Opening Brief at 19-20.

30 *See* Exhibit PGE-03, PG&E workpaper tab Green Adder – Appendix A - 2017 (citing http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=1). At this time, this url only leads to an error message. Last visited December 28, 2017.

31 McCann Testimony at 11; *see also* Joint CCAs Opening Brief at 19-20.

32 Opening Brief of Pacific Gas and Electric Company (U 39 E) (Oct. 2, 2017) at 22.

In their response to PG&E's Motion to Offer the November Update into Evidence and Admit the November Update into the Record, Marin Clean Energy, Peninsula Clean Energy Authority and Silicon Valley Clean Energy Authority reiterated these flaws with the DOE Data and, in addition, explained how these data are highly problematic because they include green tariffs of varying percentages of clean energy, whereas the "RPS Adder" used to calculate the above-market cost of PG&E's Renewables Portfolio Standard ("RPS") resources is based on 100% clean energy.[34] The MCE, PCE and SVCE Response argued that these discrepancies undercount the market value of non-IOU load serving entity ("LSE") RPS energy and thereby overcount the PCIA because the green premiums are not reflective of the actual market value of 100% green energy compared to the same "brown" power baseline used for the IOU RPS premium.[35]

The MCE, PCE and SVCE Response further argued that the inclusion of two of MCE's and SCPA's green tariffs with a "zero" premium in the DOE Adder illustrates a further problem endemic to all of the green tariffs used to calculate this indicator of the average non-IOU LSE green premiums: that, as with most of the non-IOU LSE's in the Western Electric Coordinating Council ("WECC") region, MCE's and SCP's base portfolio costs are already inflated by green power purchases compared to the "brown" power metric used for the IOU's RPS premium calculation.[36] These CCAs argued that, as a result, the rate premiums for MCE's and SCPA's green rate programs are severely underestimated relative to the brown power MPB used to determine the IOU's RPS premium, thereby decreasing the MPB and thereby leading to an improperly high PCIA.[37] Finally, the MCE, PCE and SVCE Response pointed out that the DOE database is additionally flawed in that it does not include a number of commercial and industrial class green power tariffs.[38]

The MCE, PCE and SVCE Response recognized the need to proceed on an expeditious basis to revise the 2018 MPB, but asked that the Commission make a finding regarding the inadequacy of the DOE Adder, order that the DOE data source will no longer be used as a metric for calculating any

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33 Letter to Erik Jacobsen, Director, Regulatory Relations, PG&E from Edward Randolph, Director, Energy Division, California Public Utilities Commission (November 1, 2017) at 1, *available at*: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5151-E.pdf.

34 Marin Clean Energy, Peninsula Clean Energy Authority and Silicon Valley Clean Energy Authority Response to PG&E Motion to Offer the November Update into Evidence and Admit the November Update into the Record Under Rule 13.8(C) (November 17, 2017) (the "MCE, PCE and SVCE Response").

35 *Id*. at 7.

36 *Id*. at 7-8.

37 *Id*.

38 *Id*. at 8.

component of the PCIA going forward in future ERRA dockets, and set forth a plan for correcting this problem in the future.[39]

The Proposed Decision neither references the MCE, PCE and SVCE Response nor addresses the additional inadequacies it pointed out or its request. The Proposed Decision should be revised to include several findings of fact regarding the inadequacy of the DOE Adder based on the considerable record evidence to this effect. In addition, the Proposed Decision should include a conclusion of law that the DOE Adder should no longer be used going forward for future PCIA calculations. Although the PCIA as a whole is slated for change in R.17-06-026, it is quite possible that that proceeding will not have reached conclusion by the time the Commission needs to approve PG&E's and the other IOUs' PCIA forecasts for 2019. Thus, the Commission should add ordering language to this decision setting forth a plan for correcting this problem in the future. For example, the MCE, PCE and SVCE Response suggested that the Commission could set a Track 2 of this docket that includes the other IOUs to address this issue so that it can be resolved for the 2019 ERRA forecasting applications.[40] Doing so will not only guide the 2019 ERRA forecasting proceedings but also help ensure the current methodology for calculating the MPB will not be included in a revised PCIA or new non-bypassable charge, if such rate mechanisms are adopted in the PCIA OIR (R.17-06-026).

IV. The Commission Must Resolve Inconsistencies within the Proposed Decision with respect to the Effective Date for Rate Changes.

The Proposed Decision provides inconsistent guidance on the effective date for rate changes. This inconsistency constitutes factual error that should be resolved prior to Commission approval of this Proposed Decision.

Ordering Paragraph ("OP") 1 of the Proposed Decision approves PG&E's rate proposals and its revenue requirements, which includes setting the level of the PCIA rates.[41] Item 2 of this ordering paragraph proposes that the Commission would "approve PG&E's 2018 electric sales forecast and rate proposals associated with its electric procurement related revenue requirements
to be effective in rates January 1, 2018".[42] Yet, the Proposed Decision itself states that rates should go in effect "on or after" the filing of a PG&E Advice Letter containing necessary tariff changes, which is due

39 *Id*. at 8-9.
40 *Id*.
41 Proposed Decision, OP 1.
42 *Id*.

30 days after the effective date of the decision.[43] Given the delayed issuance of this Proposed Decision, PG&E will not file such an advice letter until sometime after January 11, 2018, at the earliest. If the relief granted in these comments is granted and additional testimony and cross-examination of PG&E's evidence occurs, such rates would not go into effect for several months, potentially. OP 1 should thus be updated to account for the delays in this docket.

Furthermore, OP 1, item 2 conflicts with OP 2 of the Proposed Decision, which states that rates adopted by the Proposed Decision are effective January 1, 2018, "subject to the Annual Electric True-up process."[44] In a letter from Executive Director, Timothy Sullivan, to PG&E, dated December 14, 2017, the Executive Director approved PG&E's December 8, 2017 request to defer implementation of its AET until March 1, 2018.[45] In responses to data requests submitted by the Joint CCAs to PG&E, PG&E also appears to propose a March 1, 2018 effective date for its PCIA component.[46] The Joint CCAs support making all rate changes resulting from the Proposed Decision including the PCIA, effective on the same date as the implementation of the AET (subject to additional delays associated with the inadequacy of PG&E's evidence and the need for additional process to be afforded to the Joint CCAs). This change would ensure that all of PG&E's customers, regardless of their energy provider, are treated the same and avoids fluctuating rates by having PCIA changes occur on a different schedule than all other rate changes occurring in the AET. Thus, OP 1 item 2 should be further revised so that the effective date is also subject to the AET implementation date.

Further, the Commission should provide implementation guidance to ensure competitive neutrality. Historically, the PCIA has been amortized over a 12-month period. The inevitable implementation delay, however, will result in the PCIA being amortized over a shorter period of time, which could result in an increased monthly PCIA paid by CCA customers. The Proposed Decision does not address this issue, nor does it address whether PG&E's Commission-approved bundled customer generation costs will be recovered over fewer than 12 months. The Commission's Final Decision must address this issue and direct that PCIA and other PG&E revenue requirements be recovered over the

43 Proposed Decision at 15-16.
44 Proposed Decision, OP 2 at 20.
45 Timothy Sullivan, Executive Director, Letter to PG&E (December 14, 2017) ("Executive Director Letter to PG&E"), attached hereto as Exhibit 2.
46 PG&E Data Response ERRA-2018-PGE-Forecast_DR_Joint-CCA_001-Q01 (December 15, 2017), attached hereto as Exhibit 3.

same time period. This would ensure competitive neutrality and consistent implementation of all other rate changes being implemented in PG&E's AET process.

V. Conclusion

As explained above, the Proposed Decision errs in approving PG&E's PCIA forecast for 2018 because parties have not had an opportunity to cross-examine PG&E with respect to its additional evidence submitted on November 2, December 6 and December 11 and the evidence submitted by PG&E is insufficiently transparent to permit the Commission to make the statutorily-required findings that these rates are "reasonable," "just," and "justified." Moreover, the Proposed Decision improperly allows PG&E's PCIA rate to recover avoidable costs and to include load-based CAISO costs in its computation of the PCIA. For these reasons, the Commission should not approve the Proposed Decision and should instead order further evidentiary hearings.

With respect to the DOE Adder issue, any decision issued with respect to this Application should contain findings of fact reflecting that the DOE Data (1) have not been updated since 2015, (2) contain inaccurate green premium information, (3) contain reference to tariffs no longer in existence, (4) contain green premiums of varying percentages of clean energy, (5) underestimate the rate premiums of numerous non-IOU LSE's green tariffs, (6) lack data regarding commercial and industrial tariffs, and (7) are no longer available, and therefore no longer verifiable, on the NREL website. Based on these facts, any decision should conclude that the DOE Adder is flawed, noncompliant with D.11-12-018, and should not be used going forward for future PCIA calculations. Finally, such decision should include ordering language setting forth a plan for addressing this issue in a manner that prevents this flawed data set from being used to calculate the PCIA in the future.

Finally, the Proposed Decision should be revised to provide consistency with respect to the effective dates for rate changes, taking into account the delay in this proceeding, the need for additional evidence and process, the need for consistency with the AET implementation. The Commission's final decision should also direct that PCIA and other PG&E revenue requirements be recovered over the same time period to ensure competitive neutrality and consistent implementation.

Respectfully submitted,

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January 2, 2018

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2018 PGE – Forecast
A.17-06-005
Data Response

PG&E Data Request No.:	SCP_005-Q02		
PG&E File Name:	ERRA-2018-PGE-Forecast_DR_SCP_005-Q02		
Request Date:	July 28, 2017	Requester DR No.:	005
Date Sent:	August 23, 2017	Requesting Party:	Sonoma Clean Power
PG&E Witness:	Donna Barry / Rob Bremault	Requester:	Richard McCann

QUESTION 2

See Chapter 9 workpapers, Table 9-2 (Table 9-2 TP Indiff Variance tab)– Where does the 2018 PCIA Revenue of $583.5 million (Cell I8) come from? This is a hard value and is not found anywhere else in the workpaper. Please provide the background calculation for this value.

ANSWER 2

The $583.5 million represents 2018 PCIA revenues PG&E would collect at the 2018 PCIA forecast rates. It is derived by taking 2018 PCIA rates times the 2018 forecast non-exempt departing load. The detail of the derivation is shown in the revenue by component tab of the 2018 ERRA Forecast workpapers supporting Chapter 14, which was previously provided in SCP_002-Q01 and SCP_006-Q01. See excerpt shown below – the value $583.5 million is highlighted:

				Bundled & DA/CCA/DL		
				Present BDs	Proposed BDs	Proposed BDs
				3/1/2017	3/1/2017	1/1/2018
				Revenues at Present Rates	Revenues at Present Rates	Revenues at Proposed Rates
			CPUC Jurisdictional			
Distribution			Distribution (less CARE and PPP portion of DBDRMA adjustment)	4,082,460,564	4,082,460,564	4,070,984,302
CIA	N/A		CIA (See Note 1. Below)	(15,642,504)	(15,642,504)	0
PPP	<>N/A		Public Purpose Programs	1,093,771,796	1,093,771,796	1,089,620,377
ND	N/A		Nuclear Decommissioning	125,084,117	125,084,117	125,084,117
ECRA	N/A		ECRA	(426,582)	(426,582)	(426,582)
			Total Non-generation	5,285,247,391	5,285,247,391	5,285,262,213
DWR Bond	N/A		DWR Bond	403,595,132	403,595,132	403,595,132
CTC	N/A		Ongoing CTC/GDTCMA	82,764,937	82,764,937	78,187,399
NSGC	N/A		New System Generation Charge (aka CAM)	207,899,901	207,899,901	200,347,767
AB32 Credit	<>N/A		AB32 Revenue Return	(225,387,709)	(225,387,709)	(428,421,033)
Generation	N/A		Generation	4,970,259,299	4,970,259,299	4,912,804,650
PCIA	N/A		PCIA	503,918,070	503,918,070	583,453,557

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

December 14, 2017

Erik B. Jacobson
Director of Regulatory Relations
Pacific Gas & Electric Company
77 Beale Street, Mail Code B10C
San Francisco, CA 94177

Re: PG&E's Request to Defer the 2018 Annual Electric True-Up to March 1, 2018

Dear Mr. Jacobson:

I am in receipt of your letter dated December 8, 2017. On behalf of Pacific Gas & Electric Company (PG&E), your letter requests an extension of time to implement the 2018 Annual Electric True-Up (AET) Advice Letter 5135-E filing from January 1, 2018 to March 1, 2018, pursuant to Rule 16.6 of the California Public Utility Commission's Rules of Practice and Procedure. Energy Division approved the AET on November 14, 2017, thereby consolidating authorized and pending revenue changes, including the recovery of balances in balancing accounts previously approved for amortization, and establishing 2018 electric rates effective January 1, 2018.

PG&E requests an extension of time for the AET's implementation primarily due to uncertainty in the timing of the final decision for the 2018 Energy Resource Recovery Account (ERRA) forecast proceeding (A.17-06-005) which will impact rates. By granting an extension of the AET's implementation to March 1, 2018, PG&E explains that rate increases will occur more smoothly and customer bills will have greater stability since the deferral will allow for a gradual rate increase of 2.8% rather than a larger rate increase followed by a decrease.[1]

Additionally, PG&E states that the Power Charge Indifference Adjustment (PCIA) rate will not change until a decision is issued in the ERRA proceeding, and that it will submit a Tier 1 advice letter in December to update rates effective January 1, 2018 for decisions made outside of the AET process.[2] Thus, this extension request does not impact the timing of a rate change for the PCIA.

I agree that an extension will mean less rate volatility for PG&E customers. Therefore, PG&E's extension regarding implementation of the AET, i.e. PG&E Advice Letter 5135-E, from January 1, 2018 to March 1, 2018, is hereby granted. PG&E must still file a Tier 1 advice letter in December 2017 updating rates effective January 1, 2018, for decisions made outside the AET process. Please inform all parties noticed in the AET of this deferral.

Sincerely,

Timothy J Sullivan

Timothy J. Sullivan
Executive Director

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[1] PG&E notes that its estimates are approximate and subject to change based on actual circumstances.

[2] Those decisions are: (1) FERC-approved rates submitted in PG&E Advice Letter 5170-E, and (2) expected changes to Preliminary Statement Part I reflecting changes to the CPUC fee as per Resolution M-4832 as well as any changes necessary to franchise fee components in Part I.

PACIFIC GAS AND ELECTRIC COMPANY
ERRA 2018 PGE – Forecast
Application 17-06-005
Data Response

PG&E Data Request No.:	Joint-CCA_001-Q01		
PG&E File Name:	ERRA-2018-PGE-Forecast_DR_Joint-CCA_001-Q01		
Request Date:	December 15, 2017	Requester DR No.:	001
Date Sent:	December 22, 2017	Requesting Party:	City and County of San Francisco; Marin Clean Energy; Peninsula Clean Energy; Sonoma Clean Power
PG&E Witness:	Angelia Lim	Requester:	Nathaniel Malcolm; Joseph Weidman; Neal Reardon; James Hendry

QUESTION 1

Please confirm when PG&E plans to implement the 2018 PCIA once the Commission approves PG&E's 2018 ERRA application

ANSWER 1

PG&E plans to implement the 2018 PCIA in its next available rate change once the Commission approves PG&E's Application (A.)17-06-005 (2018 ERRA Forecast Application). Without a final decision, PG&E is unable to implement the rates presented in the 2018 ERRA Application effective January 1, 2018. As stated in PG&E's December 8, 2017 letter to the Executive Director of the Energy Division, PG&E's next anticipated rate change is March 1, 2018.

October 30, 2017

Via Regular Mail and E-Mail

Mr. Ed Randolph
Director, Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102

Re: Comments on Draft Resolution E-4882 – Relating to Pacific Gas and Electric Company's Advice Letter 4949-E and 4949-E-A, Marketing, Education and Outreach Plan

Dear Mr. Randolph:

Pursuant to Rule 14.5 of the Rules of Practice and Procedure of the Public Utilities Commission of the State of California ("Commission"), and consistent with instructions provided in the comment letter from the Commission's Energy Division, dated September 26, 2017, Marin Clean Energy ("MCE"), Sonoma Clean Power Authority ("SCPA"), and Silicon Valley Clean Energy ("SVCE") (collectively, "CCA Parties") hereby submit these comments on Draft Resolution E-4882 ("Draft Resolution"). The Draft Resolution was issued in response to Pacific Gas and Electric Company's ("PG&E") Advice Letter ("AL") 4949-E and 4949-E-A, relating to PG&E's Marketing, Education and Outreach Plan ("ME&O Plan").

As discussed below, the CCA Parties request that the Draft Resolution be revised to address the following matters. First, the Draft Resolution should acknowledge that Community Choice Aggregation ("CCA") programs are rapidly expanding throughout California, particularly in PG&E's service area. Second, the Draft Resolution should require PG&E to include and actively engage CCA representatives in the development of Marketing, Education and Outreach ("ME&O") materials. Third, the Draft Resolution should require PG&E to promptly implement a robust bill comparison tool for CCA customers. Finally**,** the Draft Resolution should be modified to confirm the expectation that PG&E's standalone application for the full default time of use ("TOU") rollout will be used as the proceeding in which parties may address PG&E's proposed cost allocation methodology for ME&O. As it is now, PG&E's proposed cost allocation for the ME&O Plan continues the practice of cross-subsidization while providing inadequate services to unbundled customers.

BACKGROUND

MCE operates California's first CCA program, and currently serves over 250,000 customers in the counties of Marin and Napa, the cities of Richmond, San Pablo, El Cerrito, Benicia, Walnut Creek, and Lafayette. In 2019, MCE will undergo an expansion to serve unincorporated Contra Costa County, the cities of Concord, Martinez, Oakley, Pinole, Pittsburg, and San Ramon, and the towns of Danville and Moraga.

SCPA is a California Joint Powers Authority ("JPA") operating a CCA program in Sonoma and Mendocino Counties. SCPA is the second operational CCA program in California and currently serves about 226,000 customer accounts which includes all of Sonoma and Mendocino Counties, except for the cities of Healdsburg and Ukiah, which have their own municipal utilities.

The Silicon Valley Clean Energy Authority ("SVCEA") is a JPA formed in 2016 to implement a CCA program, SVCE. SVCEA's members include the County of Santa Clara and eleven cities within the county.[1] SVCE launched on April 3, 2017, as the sixth operational CCA program in California. SVCE is currently serving approximately 248,000 customers.

Electric customers of the CCA Parties receive generation services from the CCA provider, while continuing to receive transmission, distribution, billing, and other services from PG&E. Under CCA programs, rates for generation services are set by local governing boards, whereas the rates for transmission, distribution, and other services are set by the Commission. This construct, where not all residential rates are set by the Commission, creates the potential for significant customer confusion in conjunction with the rollout of default TOU rates. PG&E and the CCA Parties share the same goal of helping their customers seamlessly transition to full default TOU rates as early as 2019; this is why both MCE and SCPA elected to participate in the Default TOU Pilot.

As detailed below, the CCA Parties have been engaged with PG&E and the Commission on residential rate matters. On December 16, 2016, through AL 4979-E, PG&E filed a proposal for its 2018 Default TOU Pilot. On January 24, 2017, MCE submitted a timely protest to the Default TOU Pilot. On February 7, 2017, PG&E replied to that protest. On February 24, 2017, PG&E served AL 4979- E-B. On March 16, 2017, MCE and SCPA responded to AL 4979-E-B, and requested PG&E to provide more details about its proposed long-term solution for a rate comparison tool for CCA customers in its future filing for the full rollout of default TOU rates. In its reply, PG&E stated that it will collaborate with MCE and SCPA to develop a long-term solution for a rate comparison tool for CCA customers prior to submitting its plans for the full rollout of default TOU rates. The CCA Parties are also becoming more engaged with PG&E and the Commission on ME&O matters. In an effort to further engage on ME&O matters, the CCA Parties have had representatives attend a number of ME&O workshops at the Commission this year.

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[1] The member agencies include the County of Santa Clara, and the cities of Campbell, Cupertino, Gilroy, Los Altos, Los Altos Hills, Los Gatos, Monte Sereno, Morgan Hill, Mountain View, Saratoga, and Sunnyvale.

Since CCA programs are rapidly expanding as a service model across the state, the CCA Parties seek to ensure that CCA programs and CCA customer interests are afforded due consideration in all discussions regarding the development of ME&O programs associated with the rollout of residential TOU rates. As further described below, the rapid expansion of CCA programs, with potentially different rate structures, presents unique challenges to ME&O efforts. The CCA Parties are committed to continuing to work with PG&E, the Commission and other stakeholders in order to ensure that all customers are fully and fairly informed regarding coming changes in residential rate structures.

COMMENTS

1. **The Draft Resolution Should Acknowledge Rapid CCA Expansion.**

The CCA Parties are encouraged by statements in the Draft Resolution which suggest that the ME&O Plans should remain flexible and dynamic to account for anticipated changes. For example, the Draft Resolution states "there are many unknowns in the next few years that may affect the ME&O plans in the next few years" and "[t]he ME&O Plans as submitted by the [investor-owned utilities ("IOUs")] are starting points and must remain flexible and subject to review and revision through consultation with the Working Group."[2] However, the Draft Resolution fails to mention one important and anticipated change: the rapid expansion of CCA programs, and how this expansion might impact ME&O needs.

The electric service landscape is changing significantly, with more and more communities electing to implement CCA programs, and PG&E is keenly aware of these changes. In AL 5149-E, submitted September 29, 2017, PG&E is requesting to reduce the sample size from 250,000 to 150,000 customers for the default TOU pilot, citing as justification "the numbers of PG&E customers residing in areas where a [CCA] is just beginning or planned to begin before 2019."[3] PG&E states "there has been new information that significantly increases the probability of customers departing for existing and potential CCA programs, before full default expected to take place starting Fall 2019. This has led to a 50% reduction of the total eligible Default Pilot population . . ."[4] In addition to the ten existing CCA programs in PG&E's service area, AL 5149-E lists an additional six areas where CCAs are in various stages of formation.

Since it is likely that several other CCA programs will be operational upon the full default TOU rollout, there is an enormous potential for misunderstanding among CCA customers. Because CCA customers' generation rates and distribution rates are set separately by their CCA provider and IOUs, CCA customers could potentially be misled to believe that the changes in their rates are caused by the CCA provider, and not by the state's policy. This would undermine the policy goals of default TOU, which includes shifting electricity consumption behaviors to align with electricity generation. This would also lead to customer opting out of CCA services.

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2 Draft Resolution at 35.
3 PG&E AL 5149-E at 2.
4 *Id.*

Therefore, the CCA Parties request that the Draft Resolution recognize the importance of accommodating CCA customers in PG&E's ME&O efforts in a way that recognizes the unique position of these customers. The CCA Parties are actively engaging with PG&E in the ME&O context, but assistance from the Commission is needed to ensure that future CCA providers and CCA customers will be fully and fairly informed regarding the nature of electric service they receive and associated TOU rates for this service.

2. The Draft Resolution Should Require PG&E to Include CCA Representatives in the Development of ME&O Materials.

Given the recognition that CCA providers are expected to serve a majority of the load in California in the foreseeable future, PG&E's ME&O campaign should solicit and incorporate input from CCA representatives and the CCA community to ensure that shared customers are fairly and appropriately informed regarding the nature of electric service they receive and the associated rollout of residential TOU rates for this service. Unless properly informed, confusion may arise among CCA customers.

MCE and SCPA previously entered into a settlement agreement with PG&E in PG&E's Electric Vehicle ("EV") Infrastructure and Education Program Application ("A.") 15-02-009 ("Settlement Agreement"). Under the Settlement Agreement, PG&E recognized that CCAs must have a central role in the roll-out of the EV program. Thus, PG&E agreed that CCA representatives would be able to sit on the "Program Advisory Council" for the EV program, and CCA staff members were invited to participate with PG&E staff on the selection and marketing of potential charging station sites. A similar approach is both appropriate and warranted in the context of developing TOU ME&O materials.

3. The Draft Resolution Should Require PG&E to Implement a Robust Bill Comparison Tool for CCA Customers.

CCA boards are tasked with determining the rate structure for CCA programs. While most CCA programs will presumably choose to default to TOU rates that mirror the IOUs' rate structure to avoid customer confusion, others may hesitate to do so if a robust bill comparison tool is absent. Regardless whether a CCA adopts TOU rates, CCA customers will be impacted by messaging associated with the rollout of TOU rates. Therefore, in order to avoid customer confusion, clear and consistent messages should be provided to customers.

One messaging method that can help to minimize customer confusion is to provide clear rate comparisons. Such comparisons can only be provided by the incumbent IOUs, which are statutorily defined under Assembly Bill 117 (2002) as the exclusive billing service provider.[5] It is not the CCAs' responsibility to conduct generation rate modeling, as CCA customers have been funding the IOUs' billing tools through their distribution rates. Therefore, the Commission should require PG&E to provide TOU bill comparisons not only to bundled customers but also to CCA customers.

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[5] See Pub. Util. Code § 366.2(c)(9) (The incumbent IOU shall "provide all metering, billing, collection, and customer services to retail customers that participate in [CCA] programs.").

Moreover, this bill comparison must be comparable in form and substance; any rate comparison provided to a bundled customer should also be provided to a shared CCA customer. The CCA Parties stand ready to assist and provide necessary information to PG&E to effectuate TOU bill comparison, but direction is needed from the Commission to ensure that such comparisons are implemented in a timely and comparable manner. MCE and SCPA have communicated with PG&E regarding the development of an online rate comparison tool for the Default TOU Pilot, but remain concerned that PG&E will not develop a robust rate comparison tool for the full default because of the lack of progress to date. Therefore, the CCA Parties request that the Draft Resolution be revised to direct PG&E to begin developing this tool prior to filing PG&E's upcoming rate design window application.

4. The Commission Must Further Consider the Issue of Proper Cost Allocation.

Confusion exists regarding if parties will be given an opportunity to question whether the full panoply of TOU-related implementation costs, including ME&O overall costs, should be allocated between generation and distribution rates.

The budget of TOU ME&O efforts should be allocated in a manner that reflects the fact that TOU rates will impact generation costs. It is not reasonable to allocate the entirety of TOU ME&O costs to the distribution function, and the costs of TOU ME&O efforts should be at least partially included in generation rates.

As it is now, PG&E appears to be charging the entirety of ME&O costs to distribution rates when many, if not most, of the costs appear to be attributable to generation rates. This approach would result in inequitable cost-shifting to CCA customers. Senate Bill ("SB") 790 (a CCA-centric bill) was adopted in 2011 with the intent, among other things, of addressing and correcting cross subsidization that can occur when the IOUs exercise their inherent market power. [6] In this regard, the CCA Parties request that the Draft Resolution be modified to confirm the expectation that PG&E's standalone application for the full default TOU rollout will be used as the proceeding in which parties may address PG&E's proposed cost allocation methodology for ME&O, and related costs associated with the default TOU rollout.

While the issue of cost allocation may be outside the scope of the instant matter, the CCA Parties nevertheless request that the Commission make note of this important issue in the Draft Resolution. The CCA Parties request that the Commission provide clarity and instruction as to where and how the issue of cost allocation between generation and distribution rates will be decided. The Commission can and should use the Draft Resolution to describe how the generation and distribution cost allocation split will be reviewed and determined.

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[6] *See, e.g.,* SB 790; § 2(c) ["Electrical corporations have inherent market power derived from, among other things, name recognition among…joint control over regulated operations and competitive generation services…and the potential to cross-subsidize competitive generation services."] *See also* SB 790; § 2(h) ["It is therefore necessary to establish a code of conduct, associated rules, and enforcement procedures, applicable to electrical corporations in order to facilitate the consideration, development, and implementation of community choice aggregation programs, to foster fair competition, and to protect against cross-subsidization by ratepayers."]

CONCLUSION

The CCA Parties thank the Commission in advance for consideration of these comments.

Respectfully,

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Service List – R.12-06-013
Parties to PG&E AL 4949-E and AL 4949 E-A

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Portions of AB117 concerning Community Choice Aggregation.	Rulemaking 03-10-003 (Filed October 2, 2003)

OPENING BRIEF OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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BEFORE THE PUBLIC UTILITIES COMMISSION
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OPENING BRIEF OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION

I. INTRODUCTION

Pursuant to Rule 13.11 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, the California Community Association ("CalCCA") submits this Opening Brief.

In the remaining phase of this proceeding, the Commission seeks to develop "a permanent methodology and process to implement the requirements of Section 394.25(e) [1] with respect to customers of CCAs that are involuntarily returned to service provided by investor-owned utilities [("IOUs")]."[2] Section 394.25(e) requires that if a community choice aggregation ("CCA") customer "is involuntarily returned to service provided by an electrical corporation, any reentry fee imposed on that customer that the commission deems is necessary to avoid imposing costs on other customers of the electrical corporation shall be the obligation of the [CCA]."[3] The statute also requires CCAs to "post a bond or demonstrate insurance sufficient to cover those reentry fees."[4]

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[1] All statutory references are to the California Public Utilities Code unless otherwise indicated.

[2] R.03-10-003, *Fourth Amended Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge*, at 2 (March 1, 2017).

[3] Pub. Util. Code § 394.25(e).

[4] *Id*.

To implement Section 394.25(e), the Commission must first determine what reentry fee is necessary to avoid cost-shifting *after* a CCA involuntarily returns its customers to an incumbent IOU. Since the Commission calculates this reentry fee *after* an involuntary return of CCA customers to an IOU, the reentry fee should only include an administrative fee and six months of incremental procurement costs, if any, associated with a mass reentry of customers.

The Commission must also determine what bond amount or insurance demonstration (i.e. the Financial Security Requirement ("FSR")) is necessary *now* to cover those potential reentry fees. For the reasons set forth below, the Commission should provide CCAs with three options to satisfy the FSR: (i) post a bond, cash, or letter of credit with the Commission; (ii) restrict its assets; or (iii) demonstrate sufficient self-insurance by maintaining an investment-grade credit rating. Most importantly, in setting the FSR, the Commission should take into account the low risk of CCA dissolution and the speculative nature of forecasting incremental procurement costs. Accounting for these factors, the FSR is most appropriately based on the calculated administrative costs associated with a mass reentry of the forecasted number of the CCA customers who are likely to have remained with the CCA at the time of the CCA's dissolution.

With respect to the mechanics of the FSR, the Commission should require that each CCA submit an advice letter to establish its FSR at the CCA's inception. CCAs would then submit subsequent annual advice letters to update the amount if the change to the FSR will be more than 15%. In addition, the CCA would submit an advice letter to update the amount if the CCA begins service to a new community that causes the customer count to change by 15% or more. A CCA would then post or demonstrate the FSR within 45 days of Energy Division's disposition of the CCA's advice letter.

CalCCA's FSR proposals are fair, reasonable, and would not impose unnecessary cost or risk on any IOU or CCA customers. Accordingly, the Commission should make the following findings:

1. The Commission has the discretion under Section 394.25(e) to: (i) determine what reentry fees are necessary; and (ii) account for the low risk of CCA dissolution and the speculative nature of forecasting incremental procurement costs when determining the amount of the FSR.
2. The evidence in the record supports a finding that it is very unlikely that a CCA will dissolve with no notice to the IOU or its customers. As a result, the risks of a mass involuntary return are minimal.
3. CalCCA's proposal appropriately calculates the reentry fee that will be necessary in the unlikely event of CCA dissolution. It also establishes an FSR that ensures that all customers—both CCA and IOU—bear only the costs the Commission deems necessary to insure those customers against the unlikely event of a CCA dissolution occurring without reasonable notice. The CalCCA proposal also provides the appropriate options with which a CCA may post or demonstrate the FSR, and the appropriate process for a CCA to establish and revise the FSR.
4. The Joint IOUs[5] advance a burdensome proposal that does not meet the requirements of Section 394.25(e), particularly because the IOUs seek to unreasonably require the CCAs update their FSR on a monthly basis.
5. The CCA FSR should not include incremental procurement costs even though the reentry fee does. However, if the Commission ultimately does include an incremental procurement component in the CCA FSR, the Commission should: (a) continue to reject the use of a stressed-market-based forecast to calculate the incremental procurement component; and (b) find that any forecasted negative incremental procurement costs should be netted against the administrative cost component of the FSR.

[5] The Joint IOUs are Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.

II. THE COMMISSION HAS BROAD AUTHORITY UNDER SECTION 394.25(e) TO DETERMINE THE APPROPRIATE AND NECESSARY REENTRY FEE AND FSR

The Commission should set the appropriate reentry fee and FSR to ensure that customers should not have to pay for unnecessary or unreasonable costs associated with posting or demonstrating a FSR. These financial requirements are meant to protect bundled customers from an unlikely event—not to penalize CCA customers with additional unnecessary expenses just because they choose to take service from CCAs. Further, the Commission must strive to support the state's policy requirement to "facilitate the consideration, development and implementation of [CCAs]."[6]

The Commission has broad authority to interpret the terms "reentry fee," "bond," and "insurance," because they are not defined in Section 394.25(e). The Commission has previously found that "[w]here specific terms are not defined, we must apply our broad knowledge of ratemaking principles and policy to interpret the statute in our administrative role."[7] Furthermore, an administrative agency cannot construe a statute to ignore the common meaning of the words used therein.[8] Courts have recognized that the Commission's "interpretation of the Public Utilities Code should not be disturbed unless it fails to bear a reasonable relation to statutory purposes and language" because "the agency may have 'special familiarity with

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[6] *See* S.B. 790, 2011 CA. Leg. Sess. § 2(h) (2011).

[7] *See* D.97-11-074, 1997 Cal. PUC LEXIS 1093, at *40–41.

[8] *See, e.g.*, D.16-11-022, mimeo at 189 ("In construing a statute, we must first recognize the plain meaning of the statute and show fidelity to the words the legislature has chosen."); D.14-06-029, mimeo at 18 ("When construing a statute, the Commission must first look to the words and give them their usual and ordinary meaning."); D.95-08-056, 1995 Cal. PUC LEXIS 661, at *7 (rejecting party contention that "would mean ignoring the plain language of the statute, and reading language into the statute that is not there" which "[t]he rules of statutory construction do not permit.").

satellite legal and regulatory issues,' leading to expertise expressed in its interpretation of the statute."[9]

The Commission has previously exercised its authority to interpret Section 394.25(e) by setting the reentry fee and the FSR for electric service providers ("ESPs"). Just as the Commission did in setting the reentry fee for ESPs, the Commission has discretion to determine the appropriate reentry fee for a CCA that chooses to dissolve without providing reasonable notice. In setting the FSR, the Commission also has the discretion to determine that the FSR should be set in an amount that is *different* from a forecasted reentry fee.

As the statute provides, the Commission has the discretion to ensure that the FSR serves as a form of "insurance" in the unlikely event that a CCA dissolves without reasonable notice. The Commission regularly establishes insurance requirements that are not simply a forecast of the total worst-case possibility that can be envisioned, but instead are a balance of the costs and burden of such insurance and the likelihood of the insured-against outcome actually occurring.

For example, the Commission adopted a 15–17% planning reserve margin ("PRM") as a form of insurance to ensure reliability and resource adequacy.[10] The adopted PRM did not require extreme margin levels because the Commission recognized that doing so could have a detrimental impact on other policy goals. Specifically, the Commission described the importance of "avoid[ing] setting reserves at levels that could require the utilities to make short-term investment decisions inconsistent with [California's] preferred 'loading order' of new resources."[11] It noted, for example, that "imposing a high reserve level quickly might require utilities to enter into longer-term contracts for capacity, thus crowding out preferred resources,

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[9] *See SFPP v. P.U.C.,* 217 Cal. App. 4th 784, at 786 (2013).

[10] *See* D.04-01-050 (establishing the long-term Resource Adequacy Framework requiring each load-serving entity to acquire sufficient PRM to meet its own load).

[11] *Id., mimeo* at 24.

such as demand response and energy efficiency."[12] The Commission appropriately balanced the likelihood that additional procurement margin might be necessary and the possible costs and burdens associated with that additional procurement margin.[13]

In setting the FSR for ESPs, the Commission has already recognized its broad authority under Section 394.25(e), determined that the FSR amount would only have to cover eight months of incremental procurement costs,[14] and appropriately excluded incremental procurement costs associated with large customers from the calculation of the FSR amount.[15] Here, the Commission has the authority to determine the appropriate amount of a CCA reentry fee and the appropriate CCA FSR. In doing so, the Commission should also be mindful that the CCAs and IOUs both agree that any FSR costs for a CCA will likely be passed on to a CCA's customers[16] and thus should avoid an unnecessarily high FSR.

Further, the Commission's broad authority to implement the statute must include the same risk assessment in setting the FSR that typical commercial counterparties would perform when bargaining over the amount of collateral that one counterparty will have to post or demonstrate. In typical transactions where a collateral requirement is being negotiated, a CCA is

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[12] *Id*.

[13] Similarly, in non-energy contexts, the Commission regularly balances the likelihood of the insured-against event happening against the burdens and costs of the insurance on the regulated entity in setting insurance amounts. *See, e.g.,* D.13-09-045, *mimeo* at 73 (Ordering Paragraph 6) (setting insurance requirements for Transportation Network Companies).

[14] D.13-01-021, *mimeo* at 38 (Ordering Paragraph 7).

[15] D.11-12-018, *mimeo* at 122 (Ordering Paragraph 42) (finding that the ESP FSR for incremental procurement costs should apply to small commercial and residential Direct Access customers); D.13-01-021, *mimeo* at 37 (Ordering Paragraph 1).

[16] *See* Joint IOUs/Sekhon, Hearing Transcript, Vol. 15, at 1844, line 25 to 1855, line 5.

also able to bargain with its counterparty about the amount of the collateral based on the risk.[17] In fact, for some CCAs, it is uncommon to post collateral.[18]

The Joint IOUs' argument that CCAs are customers they are in essence forced to deal with should not negate this general principle.[19] While a CCA will be able to bargain with its FSR provider based on the risk of the occurrence of what the FSR is meant to cover,[20] the Commission should also consider that same risk in setting the amount of the reentry fees and the FSR. The Commission should reject the Joint IOUs proposal to set the FSR based on the possibility—however remote—that a CCA would involuntarily return 100% of its customers to an IOU on a single day.[21]

The Joint IOUs seek to eliminate a common outcome of bargaining with respect to collateral amounts — i.e. that no collateral posting is required when risks are reasonably low. The Commission has the flexibility to determine the appropriate FSR based on the risk of CCA dissolution, in order to ensure that unnecessary or unreasonable FSR costs are not passed on to CCA customers.

III. THE RISK OF A MASS INVOLUNTARY RETURN OF CCA CUSTOMERS IS MINIMAL BECAUSE IT IS VERY UNLIKELY THAT A CCA WOULD DISSOLVE WITHOUT NOTICE

The Joint IOUs illogically ask the Commission to set the FSR based on the possibility that a CCA would dissolve without any notice whatsoever and would involuntarily return 100%

[17] *See* Joint IOUs/Sekhon, Hearing Transcript, Vol. 15, at 1859, line 20 to 1860, line 11.

[18] *See* MCE/McNeil, Hearing Transcript, Vol. 16, at 2037, lines 16–18 (MCE witness David McNeil explaining that MCE is generally not required to post collateral for its energy supply contracts).

[19] *See* Joint IOUs/Lock, Hearing Transcript, Vol. 15, at 1829, line 21 to 1830, line 5.

[20] *See* Joint IOUs/Lock, Hearing Transcript, Vol. 15, at 1830, lines 13–25.

[21] *See* Joint IOUs, Ex. JU-01 (Testimony), at 3, lines 10–20; *see also* Joint IOU/Lock, Hearing Transcript, Vol. 15, at 1801, lines 17–22.

of its customers to the IOU on a single day.[22] While the Joint IOUs have essentially focused their entire argument on that technical possibility, the Joint IOUs made no effort to dispute any of the CalCCA evidence to the contrary. For this reason, the only evidence in the record is that the risk of such an occurrence is minimal.

Where the opposing party specifically does not dispute a proffering party's evidence, the Commission should base its decision on the unrefuted evidence presented by the proffering party.[23] Accordingly, for at least the following three reasons, the Commission should accept CalCCA's unrefuted evidence to show that the risk of CCA dissolution is unlikely.

First, the risk of CCA failure is low. It would require a confluence of four unlikely events for CCA customers to be involuntarily returned to IOU service.[24] Specifically:

1) Market prices would need to become exceedingly high and remain high for several years;[25]

2) The CCA must fail to hedge against this type of market fluctuation;[26]

3) The CCA's rates would need to become substantially uncompetitive with the incumbent IOU's generation rates for a significant period of time;[27] and

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[22] Joint IOUs, Ex. JU-01 (Testimony), at 3, lines 10–20; *see also* Joint IOU/Lock, Hearing Transcript, Vol. 15, at 1801, lines 17–22.

[23] *See, e.g.,* D.93-02-036. 1993 Cal. PUC LEXIS 96, at *4 (where the Commission based its decision in part on certain evidence after finding that one party "does not dispute the evidence"); D.89-10-005, 1989 Cal. PUC LEXIS 551, at *3 (where the Commission found "no dispute concerning the evidence" and so resolved the legal question alone).

[24] CalCCA/Fulmer, Ex. CCCA-01(Opening Testimony), at 11, line 1 to 23, line 5.

[25] The evidence in the record is that actions taken by the California Legislature and the Commission since the 2000-2001 energy crisis have ensured against dramatic increases in energy prices. CalCCA/Fulmer, Ex. CCCA-01, at 12, line 6 to 16, line 4.

[26] Either the CCA must have committed to highly uneconomic contracts or the market conditions would need to be so unpredictable and so extreme that the CCA's managed portfolio would not sufficiently protect against that specific market pressure. *See* CalCCA/Fulmer, Ex. CCCA-01, at 17, line 11 to 21, line 9.

[27] This would only happen after several years in increased market pressures and assumes that the IOU rates would be less impacted by these hypothetical risking market pressures. This further assumes that CCAs would be unable to mitigate the increased pressures through their rate stabilization funds and be otherwise unable to raise revenues. Moreover, the CCA rates would have to remain uncompetitive

4) A significant amount of CCA customers would have to voluntarily choose to leave CCA service, making it difficult for the CCA to cover its fixed costs.[28]

Second, as the Legislature has required,[29] the elected officials serving on a governing board, which ultimately oversee the implementation and operations of the CCA, act as a regulatory body that protects the interests of its constituents and CCA customers. These elected officials ensure the short- and long-term stability of the CCA and will prevent dissolution without reasonable notice.[30] For this reason, under state law, the Commission is not charged with ensuring the stability of CCAs, nor must it trust that CCA staff will ensure the stability of CCAs.

The regulatory control and authority these elected officials have over a CCA establishes a level of accountability and transparency that differentiates CCAs from ESPs, which are only accountable to their shareholders.[31] Unlike ESPs, CCAs are directly accountable to the public, subject to the Brown Act for public meetings, and their records are public records.[32] These differences provide the Commission with a reasonable basis for establishing a CCA FSR that is lower than the FSR the Commission has established for ESPs.

Third, the Legislature and Commission's procurement framework for the state, including but not limited to Resource Adequacy, the Renewables Portfolio Standard, and storage

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despite the fact that increased market pressures would correspond with decreased non-bypassable charges as the Power Charge Indifference Adjustment decreases. *See* CalCCA/Fulmer, Ex. CCCA-01, at 28, lines 13–18.

[28] Significant CCA customer attrition is unlikely because even during short periods when CCA rates have modestly exceeded the IOU's rates, customer opt-outs remained low. CalCCA/Fulmer, Ex. CCCA-01, at 29, line 1 to 30, line 3.

[29] *See* Pub. Util. Code § 331.

[30] CCCA/Fulmer, Ex. CCCA-01, at 21, lines 14–18.

[31] *Id.*, at 24, lines 6–17.

[32] *Id*.

requirements for all load serving entities, including CCAs,[33] ensures stability and limits the risk that a CCA would dissolve without reasonable notice. While the Joint IOUs claim that the procurement framework "does not eliminate disruptions in the electricity market,"[34] none of the adverse events identified in the Joint IOU testimony as causing stressed market conditions have resulted in a long-enough period of high energy prices to actually have impacted a CCA—let alone cause it to fail. No CCA or ESP dissolved as a result of any of the adverse events identified by the Joint IOUs.[35]

All of the above evidence suggests that the risk of a CCA dissolving is low. Furthermore, even if a CCA decided to undergo dissolution due to bankruptcy, as a local government agency it would avail itself of the procedures contained in Chapter 9 of Title 11 of the United States Code. The Chapter 9 bankruptcy process prevents a CCA from disbanding overnight. Federal bankruptcy law requires a CCA to be "specifically authorized" by state law to enter bankruptcy.[36] Bankruptcy authorization would occur through the neutral evaluation process[37] or an emergency declaration which would require a vote of its governing board.[38]

A CCA would have to file a petition for eligibility for bankruptcy that could be disputed by creditors.[39] Furthermore, various protections prevent a CCA from being forced to suspend

[33] CCCA/Fulmer, Ex. CCCA-01, at 12, line 16 to 17, line 11.
[34] Joint IOUs, Ex. JU-02, at 8, lines 21–22.
[35] *See* CCCA Ex. 9, SCE Response to DR 2, Q19(a) and (b), SCE Response to DR 3 Q4, and SCE Response to DR 5, Q7.
[36] 11 U.S.C. § 109(c)(2).
[37] Cal. Gov't Code § 53760.3.
[38] *Id.,* at § 53760.5.
[39] *See* 11 U.S.C. § 901(a) (incorporating 11 U.S.C. § 301).

services while in bankruptcy.[40] The CCA must file a plan of adjustment of its debts[41] and may need to modify the plan before it is finalized.[42] Finally, the plan must be confirmed by the bankruptcy court.[43] Therefore, these lengthy bankruptcy proceedings would give the IOUs reasonable notice if a CCA decided to dissolve.

IV. THE CALCCA PROPOSAL APPROPRIATELY BALANCES THE RISK OF CCA DISSOLUTION WITH THE BURDEN AND COSTS ASSOCIATED WITH ESTABLISHING A FSR

A. The Commission Should Set the Amount of the CCA Reentry Fee as the One-Time Administrative Costs Plus Six Months of Incremental Procurement Costs

CalCCA did not provide an affirmative proposal for setting the reentry fee at the time of a CCA's dissolution. However, based on the evidence presented by the Joint IOUs for its reentry fee proposal,[44] a CCA's reentry fee at the time of CCA dissolution should be based on the administrative costs plus six months of incremental procurement costs, if any, for the number of customers that the CCA has involuntarily returned to the IOU's bundled service at the CCA's dissolution.

With regard to the administrative cost component of the reentry fee, the Commission should ensure that the IOU's administrative costs are reasonable and consistently set throughout the state. The Commission should seek to resolve the discrepancies in the administrative costs for each IOU as described in section IV.B below so that all CCAs are treated similarly.

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[40] *Id*., at § 901(a) (incorporating 11 U.S.C. § 362 which provides an automatic stay of other legal and administrative actions and requires creditors to seek recovery in the bankruptcy court); *see also* 11 U.S.C. §§ 903 and 904 (prevents the bankruptcy court from interfering with the powers of the CCA, the property or revenues of a CCA, or the CCA's use of income-producing property).
[41] 11 U.S.C. § 941.
[42] *Id., at* § 942.
[43] *Id., at* § 943(b).
[44] *See* Joint IOUs, Ex. JU-01, at 14–19.

With regard to the incremental procurement cost component for the reentry fee, six months of incremental procurement should be sufficient for the IOUs to successfully procure any resources needed to cover a mass reentry of CCA customers to IOU bundled service. Currently, a CCA customer who voluntarily elects to return to IOU bundled service is required to provide the IOU with six months' advance notice to allow IOUs to conduct any incremental procurement that is necessary before the CCA customer returns to bundled service.[45] There is no compelling reason that an IOU would need more than that same six-month period to successfully procure additional resources to cover a mass reentry.

While the Joint IOUs may try to distinguish the procurement planning for "self-elected voluntary returns" by noting that these returns involve "small numbers [of CCA customers] here" and not a "mass involuntary return,"[46] the number of customers should be irrelevant. In fact, the economies of scale associated with a mass involuntary return of customers may actually expedite obtaining the appropriate amount of incremental procurement, to the extent that any incremental procurement is even needed.

Similarly, while ESPs are required to provide eight months of incremental procurement costs as part of the reentry fee in the event that an ESP dissolves without notice,[47] there are important distinctions between CCAs and ESPs that make a shorter period of incremental procurement costs for CCA reentry fees appropriate. First, even if a CCA does not give any formal notice of its dissolution, the IOU will have notice because, as discussed above, the conditions that will be necessary for a CCA's dissolution will be obvious to the IOU, which

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[45] *See* PG&E Electric Rule 23.L.1.a; SCE Rule 23.L.1; SDG&E Rule 27.L.1.a.

[46] Joint IOUs/Sekhon, Hearing Transcript, Vol. 15 at 1836, line 27 to 1837, line 7.

[47] D.13-01-021, *mimeo* at Appendix 1.

would not be the case with ESPs.[48] Second, even if a CCA simply votes to disband, it cannot do so overnight. The dissolution process would be conducted in public meetings, unlike for an ESP, which would provide the IOU with significant notice of the CCA's decision to dissolve.[49] These important distinctions support a shorter period for incremental procurement costs that are included in the CCA reentry fee than in the ESP reentry fee.

B. The Commission Should Set the Amount of the FSR at the Administrative Cost Component of the Reentry Fees Unless a CCA Has an Investment Grade Credit Rating

While an incremental procurement component should be included in the calculation of a reentry fee, the FSR should only be set at the administrative cost component of the reentry fee for the following reasons.

1. A CCA Without an Investment Grade Credit Rating Should Have Its FSR Based on an Estimate of Remaining CCA Customers Multiplied by the CCASR Fee Plus the Mass Enrollment Fee

Given the minimal risks of CCA dissolution without providing reasonable notice, the Commission should set the FSR for a CCA without an investment grade credit rating at just the administrative component of the reentry fee.[50] Setting the FSR at the administrative component of the reentry fee strikes the proper balance between the risk of CCA dissolution and the burdens and costs associated with posting or maintaining a FSR. As discussed above, establishing a FSR in this manner is consistent with insurance levels the Commission has set in other proceedings.[51] Setting the FSR at the administrative component of the reentry fee will also ensure that the FSR is reasonable, consistent throughout the state, easily calculated, and verifiable. For instance, in

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[48] *See supra* Section III.
[49] *See* CCCA/Fulmer, Ex. CCCA-01, at 24, lines 6–17.
[50] CCCA/Fulmer, Ex. CCCA-01, at 34, lines 1–13.
[51] *See supra* Section II.

setting the FSR for ESPs, the Commission chose "an administratively simpler approach" that "still provid[ed] a reasonably accurate basis to calculate cost responsibility."[52]

By calculating the FSR using the sum of the CCA Mass Enrollment Fee plus an estimate of the number of customers being switched over to bundled service multiplied by the tariffed Community Choice Aggregation Service Request (CCASR) fee,[53] the Commission will set a simple and verifiable FSR that allows for consistency across the state. Use of the Mass Enrollment Fee makes sense because the return would be en masse, not a series of one-off transfers. Consequently, the Mass Enrollment Fee and the CCASR[54] provide a better and more consistent proxy for the mass enrollment costs associated with an involuntary return than does the reentry fee proxy the Joint IOUs have asked the Commission to use.

In determining the FSR, the Commission should not assume that 100% of a CCA's customers will be involuntarily returned. Rather, the Commission should multiply the then-current number of CCA customers by a value between 0.6 or 0.8 to account for customers that may choose to leave a struggling CCA before it dissolves.[55]

The administrative component of the ESP FSR was set at the number of customers multiplied by the "customer reentry fee" from IOU tariffs[56] associated with one-off transfers,[57] even though economies of scale associated with a mass reentry suggest that using the Customer Reentry Fee would establish an overly conservative estimate. However, if the Commission

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[52] D.13-01-021, *mimeo* at 33 (Finding of Fact 5).

[53] CCCA/Fulmer, Ex. CCCA-01, at 35, line 17 to 36, line 18.

[54] *See* Ex. CCCA-09*,* SCE Response to Q3, DR 7d (establishing that the CCASR fees across the 3 IOUs are pretty consistent ($0.79 for PG&E, $0.98 for SCE, and $1.12 for SDG&E)).

[55] CCCA/Fulmer, Ex. CCCA-01, at 37, line 1 to 38, line 3.

[56] This "customer reentry fee" found in the IOU tariffs is an amount that is different than the CCA reentry fee discussed throughout the brief. To ensure clarity, this brief will refer to the "Customer Reentry Fee" when referring to the customer reentry fees found in the IOU tariffs.

[57] D.13-01-021, *mimeo* at Appendix 1, at 4.

determines that the Customer Reentry Fee is a reasonable proxy for the administrative costs of a mass reentry of CCA customers to IOU bundled service, the Commission should harmonize the current disparate Customer Reentry Fees among the IOUs. PG&E should not be authorized to use a Customer Reentry Fee of $4.24 per customer account while the Customer Reentry Fee is only $.50 for SCE.[58] Should the Commission, in setting the FSR, choose the Customer Reentry Fee as a proxy, the Commission should base the administrative costs on a fixed per customer charge and set this charge at SCE's Customer Reentry Fee of $0.50/customer for the entire state.

2. An Investment Grade Credit Rating Is Further Indication that There Is Little to No Risk for an IOU, and Thus No Bond Should Be Necessary for a CCA With an Investment Grade Credit Rating

The Commission should adopt the "Credit Rating Screen" put forth by MCE that would preclude the need for any collateral posting, including the FSR, for those CCAs with an investment grade[59] long-term issuer or issue credit rating. As MCE describes, an investment grade credit rating provides commercially reasonable assurance that a rated entity will not suddenly or imminently default and that it will continue operating and serving customers for the foreseeable future.[60] Thus, as long as a CCA is able to maintain an investment grade credit rating, there is insufficient need or risk present to justify a requirement to post collateral.[61]

While the Commission has not allowed such a screen for ESPs,[62] the further accountability and transparency of CCAs make CCAs distinguishable from ESPs and support the use of such a credit screen for CCAs.[63] The Commission should recognize that CCAs are held to

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[58] Exs. CCCA-06 and 07; Joint IOUs/Gutierrez, Hearing Transcript, Vol. 15 at 1908, lines 19–27.

[59] An "investment grade credit rating" is a credit rating of Baa3 or better from Moody's or BBB- or better from Standard and Poor's. MCE/McNeil, Ex. MCE-01 (Opening Testimony), at 3, lines 13–15.

[60] MCE/McNeil, Ex. MCE-01, at 4, lines 9–11.

[61] *Id.*, at 5, lines 14–16.

[62] D.11-12-018, *mimeo* at 75.

[63] *See supra* Section III.

a higher standard of accountability and transparency than private actors like ESPs because they are directly accountable to the public, subject to the Brown Act for public meetings, and their records are public records.[64] Accordingly, the reduction in risks associated with CCAs being held to a higher standard than an ESP justifies using an investment grade credit rating to eliminate the need to post a FSR. This showing represents a form of self-insurance used to satisfy the FSR.[65] There is no need to add costs to, and drain the liquidity of, financially sound and credit-rated CCAs by forcing them to post or maintain a FSR.

3. The Joint IOU Concerns with Regard to a FSR Based Solely on Administrative Costs Are Overblown

The Joint IOUs base most of their argument for an incremental procurement cost component to the FSR on a series of risks and exposures that they allege are associated with the involuntary return of customers.[66] Yet, if the IOUs were as concerned about the risks as they suggest, the Commission could reasonably have expected them to have taken some action by now to protect or hedge against any of the risks and exposures that they allege they are experiencing with the FSR set as it is today (*e.g.*, the IOUs should have bought some form of insurance or restricted assets to ensure sufficient liquidity).

The Joint IOUs' own inactions to address these alleged risks undercut their supposed "concerns." In fact, the Joint IOUs admit that they have not taken any actions outside of this proceeding to actually address or mitigate the risks and exposures that they allege result from the current FSR.[67] Thus, if the Commission sets an FSR based only on administrative costs, which is an order of magnitude similar to the current FSR amount that active CCAs have posted with

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[64] CCCA/Fulmer, Ex. CCCA-01, at 24, lines 6–17.
[65] MCE/McNeil, Ex. MCE-01, at 6, lines 20–22.
[66] Joint IOUs, Ex. JU-01, at 11, line 12 to 13, line 16.
[67] *See* Ex. CCCA-09, DR 5, Q1-5.

the Commission (usually $100,000), the Joint IOUs would not be subject to any more risk or exposure than they currently allege they face and have done nothing to address.

C. The FSR Should Be Posted with the Commission After Energy Division Confirms the Amount Following an Annual CCA Advice Letter Filing

Given the simple calculation of administrative costs necessary to determine the appropriate amount of the FSR, the Commission should allow the CCAs to confirm the appropriate FSR by submitting an advice letter to Energy Division with notice to the appropriate IOU. Since posting the FSR is an obligation of the CCA, the CCA should be the entity submitting the advice letter. The advice letter should be filed after the Commission issues a decision in this proceeding or upon inception of a new CCA and then on an annual basis to update the amount. A CCA would then post or demonstrate the FSR within 45 days of the Energy Division's disposition of the CCA's advice letter.[68]

If during the annual filing, a CCA's recalculated FSR is within 15% of the FSR currently in place, no change would be necessary to the FSR. Similarly, if a CCA takes an action such as providing service to a new community that causes its customer count to change by 15% or more, then the FSR should be immediately recalculated and updated with a new advice letter.[69] Given that the administrative cost component of the reentry fee should not change dramatically from year to year, this set of calculations will ensure long-term stability and predictability of the FSR.

D. Regardless of Whatever FSR Requirement Is Established, the Commission Should Allow Flexibility in the Manner that a CCA Meets the Requirement

The Commission should allow the CCAs flexibility in the manner in which the CCA posts or demonstrates the FSR by allowing a CCA that does not have an investment-grade credit rating to either (i) post a bond, cash, or letter of credit with the Commission, or (ii) restrict its

[68] CCCA/Fulmer, Ex. CCCA-01, at 38, lines 9–16.
[69] *Id.*, at 38, lines 4–8.

assets.[70] This range of options allows CCAs of different sizes and maturities to meet the FSR obligation while avoiding unnecessary costs or drains on liquidity. The Commission should reject the Joint IOUs' proposal that the Commission require the CCAs to use only cash deposits or letters of credit to satisfy the FSR.[71]

The Joint IOUs would have the Commission reject the clear direction from the Legislature in this regard. The statute itself uses the term "bond." When a statute does not define a commonly-used word, the courts will often look to the dictionary definition of the word.[72] The word "bond" is defined at an "an insurance agreement pledging that one will become legally liable for financial loss caused to another by the act or default of a third person or by some contingency over which the third person may have no control."[73] While the Commission may expand on that term, under rules of statutory construction, an administrative agency cannot construe a statute to ignore the common meaning of the words used therein.[74] The Commission previously relied on these principles when it allowed ESPs to post a bond in compliance with their FSR requirement.[75]

In general, CCAs should be allowed maximum flexibility as to how they can meet the FSR. In addition to bonds, cash, and letters of credit, the Commission should allow a CCA to restrict assets on a balance sheet for the sole purpose of satisfying the FSR posting. The CCA would name the assets in the advice letter that updates the FSR calculation, and the Commission's approval of the advice letter would create a regulatory restriction on that asset

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[70] *Id.*, at 39, lines 3–7.

[71] Joint IOUs, Ex. JU-02 (Rebuttal Testimony), at 31, lines 15–16.

[72] *See, e.g.*, *River Lines, Inc. v. P.U.C.,* 62 Cal.2d 244, 247 (1965) (using dictionary, among other sources, to show "ordinary concept of a carrier" under Public Utilities Code).

[73] *See* https://www.merriam-webster.com/dictionary/bond.

[74] *See supra* footnote 8.

[75] D.13-01-021, *mimeo* at 29–30, 35 (Conclusions of Law 1).

sufficient to cover the IOU until a different FSR is approved via a new advice letter. The restricted assets will be notated as restricted on the CCA's audited financial statements and other financial reports.

A flexible approach to meeting the FSR requirement would allow CCAs to reduce the costs necessary to post or maintain the FSR, which would benefit CCA customers. Accordingly, and in response to the Administrative Law Judge's question regarding the matter,[76] the type of costs included in establishing the amount of the FSR—whether administrative alone or administrative and procurement—is irrelevant to allowing CCAs the flexibility to post or maintain whatever form of FSR that the CCA deems appropriate.

V. THE JOINT IOU PROPOSAL FOR A MONTHLY RESET OF THE FSR IS INAPPROPRIATE, UNNECESSARY, AND BURDENSOME

The Joint IOUs propose to require the CCAs to update the FSRs on a monthly basis.[77] The Commission should reject the Joint IOU proposal because updating the FSR on a monthly basis would be inappropriate, unnecessary, and burdensome.

The statute's use of the word "bond" as the financial security instrument that a CCA should use to meet the financial security requirement suggests that the Legislature did not intend such a requirement. The Joint IOU witness admitted that bonds are "usually …set for a fixed amount" [78] and are "not adjusted up and down on a monthly … basis."[79] The witness admitted that he has "never" actually seen a bond amount change and questioned the practicality of doing so given the time investment it takes to negotiate the language of a bond.[80] By the plain meaning

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[76] MCE/McNeil, Hearing Transcript, Vol. 16, at 2041, lines 5–24.
[77] Joint IOUs, Ex. JU-01 at 21, lines 18–20 and 22, lines 1–2.
[78] Joint IOUs/Lock, Hearing Transcript, Vol. 15, at 1813, lines 12–13.
[79] *Id.*, at 1813, lines 13–15.
[80] *Id.*, at 1813, lines 7–12.

of the term, had the Legislature intended for the FSR to be set on a monthly basis, the statute would not have used the word "bond."

The Joint IOU proposal to update the FSR on a monthly basis also fails to recognize how CCAs and municipal entities operate. As described in the testimony, it would be difficult and costly for a CCA to establish a variable financial instrument to meet a FSR that fluctuated on a monthly basis.[81] In fact, the Commission specifically rejected the IOUs' request for monthly updating of the ESP FSR, because "more frequent updating could prove to be administratively burdensome without offsetting benefits in terms of increased accuracy or timeliness."[82]

While the Joint IOUs contend that some market participants, like the Joint IOUs themselves, may choose to enter into power and gas contractual commitments that require daily or monthly adjustment of collateral,[83] CCAs would not enter into such contracts because of the realities of their business practices. In general the CCAs do not include any monthly adjustments requirement in their bilateral power and gas contractual commitments.[84] Requiring CCAs to adjust letters of credit on a monthly basis would likely mean that the CCAs would have to establish and pay the costs associated with letters of credit that far exceed the credit support that is actually required to meet the current FSR.[85] The Commission should not impose a monthly revision obligation of the FSR on CCAs that would not normally agree to any such requirement.

In addition, while the Joint IOUs contend that the FSR would fluctuate no more than on a monthly basis, the Commission should recognize that under the Joint IOU proposal, the CCA would only have a few days to post a revised FSR. The IOU would calculate the new FSR on a

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[81] CalCCA/Perl, Ex. CCCA-02, at 36, line 11 to 40, line 15.

[82] D.13-01-021, *mimeo* at 25.

[83] S*ee* Joint IOUs, Ex. JU-02 at 17, lines 4–7.

[84] CalCCA/Perl, Hearing Transcript, Vol. 16, at 2013, line 28 to 2014, line 11, and 2028, lines 2-10.

[85] CalCCA/Perl, Ex. CCCA-02, at 36, line 11 to 40, line 15; CalCCA/Perl, Hearing Transcript, Vol. 16, at 2012, lines 12–19 and 2013, line 28 to 2014, line 11.

monthly basis, then the CCA would have to check it, then the Commission would have to finally authorize the new FSR, and then the CCA would have to post the revised amount. The administrative burden and costs associated with revising a financial instrument in only a few days would be considerable, if not impossible.[86]

Assuming the Commission approves an incremental procurement cost component to the FSR, the Joint IOU proposal could subject CCAs to potentially significant monthly spikes to their FSRs due to a temporary spike in market prices. A longer-term approach would better reflect the actual procurement risks. It would also ensure a better correlation with IOU generation rates used to determine the incremental procurement cost component under the Joint IOU proposal. While an IOU's average bundled service generation costs would similarly fluctuate during a stressed environment, IOU generation rates are only revised following the completion of an annual Energy Resource Recovery Account ("ERRA") application.[87]

VI. PROCUREMENT COSTS SHOULD NOT BE INCLUDED IN THE FSR

During the last six years, the projected revenues from returned customers based on the IOU average bundled generation rate have exceeded the forecasted costs to serve those returned customers.[88] Consequently, during that entire period, the FSR utilizing the Joint IOU proposal would not have included a procurement component. Yet, the Joint IOUs continue to insist on the inclusion of an incremental procurement component to the FSR based on hypothetical and highly speculative costs. These costs, which are intended to cover the projected incremental procurement costs for the IOU to serve the involuntarily returned CCA customers, should not be included in the CCA FSR for two main reasons.

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[86] *See* CCCA/Perl, Ex. CCCA-02, at 36–40.

[87] Joint IOUs/Sekhon, Hearing Transcript, Vol. 15, at 1840, lines 6–18.

[88] CCCA/Fulmer, Ex. CCCA-02, at 14, line 16 to 20, line 8.

First, the very uncertainty of the market conditions for which the IOUs desire to have an FSR with a procurement component makes inclusion of those procurement costs inappropriate. The Commission has often balked at establishing requirements or setting values where forecasts are uncertain.[89] By establishing a FSR based on a projection of procurement costs utilizing forecasts that might not come to bear, the Commission would needlessly impose significant additional costs on CCA customers when the risk of CCA dissolution is small.

Second, the FSR will only include procurement costs in stressed market conditions. In those conditions, an IOU would likely need to increase its rates. In an environment where the IOU is increasing rates, it is even more speculative to determine what *incremental* procurement cost might actually be imposed at the time of a CCA's dissolution, especially because the IOU's need for incremental procurement might be mitigated by preexisting contracts the IOUs have procured on behalf of departed load.[90] Furthermore, even if CCAs must raise rates during a stressed market, CCA customers would be less likely to seek a voluntary return to bundled service, which could lead to a CCA's dissolution, when the IOU is also raising its rates to address increased procurement costs.

A. Even if the Commission Approves Incremental Procurement Costs as Part of the FSR, the Commission Should Reject the Use of a Stressed-Based Forecast

If the Commission rejects their request for a monthly update of the FSR but allows for incremental procurement costs, the IOUs request that the FSR be based on a stressed-based forecast.[91] The Commission has repeatedly rejected using the stressed-based forecast with

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[89] *See, e.g.,* D.16-01-032, *mimeo* at 62 (Conclusions of Law 4); D.04-12-014, *mimeo* at 18 (Findings of Fact 3).

[90] CalCCA/Fulmer, Ex. CCCA-02, at 31, lines 3–10.

[91] Joint IOUs, Ex. JU-01, Appendix C.

respect to setting the FSR for ESPs[92] because it did not offer a suitable framework. The Commission should again reject such an approach here.

B. If the Commission Approves Incremental Procurement Costs, the Commission Should Net Out Forecasts of Negative Procurement Costs and Accordingly Reduce the FSR

A negative FSR incremental procurement cost would occur when the forecast of the revenues the IOUs would collect from returned CCA customers is greater than the IOU's costs for new procurement to serve those customers.[93] In this scenario, the involuntary return of CCA customers would be forecasted to result in *savings* for the IOU's preexisting bundled customers.[94]

Nonetheless, while the Joint IOUs' proposal could result in a forecast of negative procurement costs for the IOUs, it would not affect the FSR for the CCAs.[95] The Joint IOUs' proposed calculation for the CCA FSR would ignore those benefits. Instead, the Joint IOUs propose to zero-out, rather than credit back, these projected savings.[96]

In establishing the ESP FSR, the Commission allowed the negative incremental procurement costs to offset up to 100% of the calculated incremental administrative costs.[97] As the Commission explained,"[s]ince both administrative costs and procurement costs are incurred in connection with an involuntary return of DA customers to bundled service, it is reasonable to

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[92] CalCCA/Fulmer, Ex. CCCA-01, at 7–10 (explaining that the Commission has rejected the IOUs' proposal to use stressed-market based FSR for ESP FSRs calculations); *see also* D.11-12-018, *mimeo* at 82 (finding that "the proposed bond model offered by PG&E/SCE does not offer a suitable framework for determining the applicable ESP bond amount.")

[93] Joint IOUs/Sekhon, Hearing Transcript, Vol. 15, at 1842, lines 22 to 1843, line 1.

[94] CalCCA/Fulmer, Ex. CCCA-02, at 27, lines 8–9.

[95] *See* Joint IOUs, Ex. JU-01, Appendix E.

[96] *Id.*, at 29, lines 1–4 ("[T]he Joint Utilities propose that negative incremental procurement costs be set to zero (i.e. if the Forecast Cost of New Procurement is lower than the Forecast Revenues, then there is zero Incremental Procurement Cost Exposure)."); Joint IOUs/Sekhon, Hearing Transcript, Vol. 15, at 1842, lines 17–21.

[97] D.13-01-021, *mimeo* at 31.

consider the net effect of both elements of costs in determining the amounts, if any, necessary to compensate the IOU and to avoid cost shifting to other customers."[98] This rationale also applies to an involuntary return of CCA customers. Thus, were the Commission to include an incremental procurement cost component in the FSR, the Commission should reduce the total FSR by any benefit that would be associated with CCA customers returning to the IOU.

Respectfully submitted,

By: /s/ ______________________________

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November 6, 2017

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4840-6804-7444v.1 0110209-000001

[98] *Id.*

November 13, 2017

California Energy Commission
Dockets Office, MS-4
Re: Docket No. 17-IEPR-1
1516 Ninth Street
Sacramento, CA 95814-5512

Subject: MCE Comments on Draft 2017 IEPR Report

Marin Clean Energy (MCE) hereby submits its comments on the Draft 2017 Integrated Energy Policy Report (Draft 2017 IEPR) released by the California Energy Commission (CEC). First and foremost, MCE thanks the CEC staff for their hard work on the report. MCE also appreciates the acknowledgement of the growth of Community Choice Aggregators (CCAs) in California, as well as the changes to the electricity market spurred by CCAs.

MCE provides comments on two matters highlighted in the Draft 2017 IEPR: 1) the ability of CCAs to secure the financing needed for long-term investments, and 2) the role of CCAs in fostering the growth of Distributed Energy Resources (DERs) in California.

I. Introduction

MCE is the first operating CCA in California. As stated in the Draft 2017 IEPR, there is a rapid growth of CCAs throughout California.[1] MCE currently serves over 250,000 customers throughout the counties of Marin and Napa, the cities of Richmond, San Pablo, El Cerrito, Benicia, Walnut Creek, and Lafayette. In 2018, MCE will include the new communities of unincorporated Contra Costa County, the cities of Concord, Martinez, Oakley, Pinole, Pittsburg, and San Ramon, and the towns of Danville and Moraga. CCA customers receive generation service from their CCAs, while the incumbent utilities continue to provide distribution, transmission, billing, and metering services to these customers.

Like other CCAs, MCE was established by the local communities it serves to reduce greenhouse gas emissions. CCAs reduce greenhouse gas emissions by providing communities within its service area the choice to purchase alternative energy products to PG&E's product. MCE's locally elected Board of Directors, which has the sole authority to determine MCE's procurement and planning, has set the policy for MCE to procure 100% of its portfolio from Greenhouse Gas-(GHG) free resources by 2025.

[1] Draft 2017 IEPR at page 31.

II. CCAs Have Proven Their Ability to Secure Financing to Invest in Long Term Energy Contracts

There is some concern expressed about the ability of CCAs to secure financing needed for long-term investments in Draft 2017 IEPR.[2] However, operational CCAs have successfully secured long-term energy contracts. Since its launch, MCE has committed over $1.6 billion to build 813 MW of new California renewable energy projects, including $902 million for solar, $665 million for wind, and $17 million for biogas projects. MCE has executed numerous contracts that are over 10 years in length, up to 25 years.

Other CCAs have also begun to sign long term contracts as their growth continues and load forecast stabilizes. Sonoma Clean Power (SCP), for instance, has at least 6 contracts that have begun delivery and are 20 years in length. Peninsula Clean Energy (PCE), one of the CCAs launched in 2016, has secured a 20-year 200 MW solar contract to serve its customers.

Furthermore, as directed by SB 350 and California Public Utilities Commission (CPUC) Decision (D.) 17-06-026, 65 percent of the procurement of all retail sellers use to meet their Renewable Portfolio Standard (RPS) requirement must come from contracts of 10 years or more in length, beginning in 2021.[3] CCAs are not exempted from this regulation, and MCE is looking forward to continue to foster the growth of renewable energy in California by securing financially viable long-term contracts. Concerns about CCAs' abilities to finance procurement projects are unfounded.

III. CCAs Are Well-Positioned to Drive Innovation and Technology Deployment

The Draft 2017 IEPR pointed out that programs funded by the Investor Owned Utilities (IOUs) have spurred the majority of the growth of DERs in California, and that the growth of CCAs is creating uncertainty for these programs.[4]

First, it should be noted that many of these DER programs, including storage and electric vehicles, are largely funded through the distribution function of the IOUs' revenue. As stated above, CCA customers continue to receive distribution, transmission, and other services after departing for CCA generation services. The IOUs continue to collect the revenue requirement for those services from CCA customers. While the growth of CCAs and departing loads create

[2] Draft 2017 IEPR at page 7.
[3] Public Utilities Code Section 399.13(b)
[4] Draft 2017 IEPR at page 135.

uncertainties for the generation revenues of the IOUs, distribution function revenue is unaffected by CCAs.

Second, the DER programs of the IOUs require CPUC approval, which can create delay in implementation and reduce the IOUs' appetite to explore different technologies and business models. However, due to the regulatory authority of their locally elected Boards of Directors, the CCAs are nimble and do not require lengthy applications for pilot programs. Unlike the IOUs, CCAs are much more connected with local communities they serve, and each CCA is in a unique position to test technologies that best suit their communities' and programs' needs. MCE encourages the CEC to leverage CCAs as laboratories of innovation to develop and test the market-readiness of various DERs.

However, several barriers exist for CCAs to deploy DERs. The most significant challenge is data access. Currently, the IOUs collect, store, and control customer- and utility- centered data, and significant obstacles continue to prevent CCAs, other Load Serving Entities (LSE), and third-party providers from accessing useful data that can inform planning. The transfer of AMI data from the IOUs to the CCAs are often delayed, or in format that is not workable for settlement or analysis. Furthermore, CCAs have no insight into what DER services customers have already received from the IOUs, which could potentially result in providing duplicative services that are costly and do not result in additional environmental or economic benefits.

As public agencies that are subject to strict customer privacy regulations, CCAs should be allowed to access customer data in a streamlined manner to enable them to offer customers innovation products and services. The CEC, working along with other energy agencies, should consider data access an important element in its roadmap for integrating high levels of DERs in the electricity system. MCE looks forward to working with the CEC, as well as the CPUC and the California Independent System Operator (CAISO), in reducing and overcoming these barriers.

IV. Conclusion

MCE appreciates the CEC for highlighting the growth of CCAs, as well as challenges and opportunities that are associated with the growth of CCAs in the Draft 2017 IEPR. MCE respectfully requests that the CEC incorporate the comments of MCE in its final 2017 IEPR, and looks forward to robust participation in the 2017 IEPR proceeding.

Sincerely,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
And Related Matters	Application 17-01-014 Application 17-01-015 Application 17-01-016 Application 17-01-017

MARIN CLEAN ENERGY
THREE-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION

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November 15, 2017

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

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
And Related Matters	Application 17-01-014 Application 17-01-015 Application 17-01-016 Application 17-01-017

**MARIN CLEAN ENERGY
THREE-DAY ADVANCE NOTICE OF EX PARTE COMMUNICATION**

Pursuant to Rule 8.4 of the Commission's Rules of Practice and Procedure and Public Utilities Code Section 1701.3(h)(2), Marin Clean Energy ("MCE") hereby gives advanced notice of a meeting with Jennifer Kalafut and Shannon O'Rourke, advisors to Commissioner Peterman. The meeting is scheduled on November 21, 2017 at 3:00 pm. Beckie Menten, Director of Customer Programs; Alice Stover, Manager of Customer Programs, Policy, and Planning; Michael Callahan, Policy Counsel; and Jacob Schlesinger, outside counsel will be in attendance for MCE.

Respectfully submitted,

/s/ Troy Nordquist

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November 15, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Portions of AB117 concerning Community Choice Aggregation.	Rulemaking 03-10-003 (Filed October 2, 2003)

REPLY BRIEF OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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November 20, 2017

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

Order Instituting Rulemaking to Implement Portions of AB117 concerning Community Choice Aggregation.	Rulemaking 03-10-003 (Filed October 2, 2003)

REPLY BRIEF OF CALIFORNIA COMMUNITY CHOICE ASSOCIATION

I. INTRODUCTION

Pursuant to Rule 13.11 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, the California Community Choice Association ("CalCCA") submits this Reply Brief.

The primary dispute in this proceeding involves the Commission's discretion. Specifically, does the Commission have discretion under Section 394.25(e)[1] to (i) set both the reentry fee and the Financial Security Requirement ("FSR")[2] for community choice aggregators ("CCAs"), and (ii) determine that the FSR should be set in an amount *different* from a forecasted reentry fee? The investor-owned utilities ("Joint IOUs") contend the Commission has no such discretion.[3] However, as discussed in CalCCA's opening brief and below, the Commission has already found it has discretion under the law and Commission regulation to make these determinations.[4]

The Commission should apply that discretion to establish (i) a reentry fee, and (ii) a sufficient FSR based on the low risk of sudden CCA dissolution, in so doing the Commission

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[1] All statutory references are to the California Public Utilities Code.

[2] While the Joint IOUs attempt to define a number of terms in JU-01 Appendix A and CalCCA uses a number of those terms in its opening brief and testimony, the precise definitions of those terms are clearly in dispute despite the Joint IOUs' contention otherwise. *See* Joint IOUs Opening Brief, at 2.

[3] *Id.*, at 11–12.

[4] *See* CalCCA Opening Brief, at 4–7; *infra* at Section II.

will ensure that CCA customers are not required to pay for unnecessary or unreasonable costs associated with posting or demonstrating the FSR.

The primary dispute is not, as the Joint IOUs insist, whether "the statutory consumer protection provisions [of Section 394.25(e)] extend to all incremental costs related to mass involuntary returns – including procurement costs – or are they instead limited to relatively *de minimis* incremental administrative cost?"[5] The construct of the Joint IOUs' question aims to leave the Commission with only two options—(i) both the reentry fee and FSR include incremental procurement costs or (ii) neither includes incremental procurement costs. However, the Commission has more options.

The Commission should instead opt to follow CalCCA's recommendation to include administrative costs and incremental procurement costs in the reentry fee,[6] but set the FSR based only on the administrative component of the reentry fee.[7] The Commission would properly establish the FSR as an insurance requirement and balance the need to protect CCA customers in the case of sudden CCA dissolution without burdening those same customers with unreasonable costs to insure against such an unlikely occurrence. The Commission should reject the Joint IOU proposal that ignores the balancing process and seeks to eliminate the discretion the Commission has under Section 394.25(e).

II. THE COMMISSION HAS THE DISCRETION TO DETERMINE A "SUFFICIENT" FSR

As CalCCA explained in its opening brief, the Commission has broad authority to interpret the terms used in Section 394.25(e) that are not defined in the statute[8] including the

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[5] Joint IOUs Opening Brief, at 11–12.
[6] *See* CalCCA Opening Brief, at 11–13; *infra* at Section III.
[7] *See id.,*, at 13–15; *infra* at Section V.
[8] *Id.*, at 4.

term “sufficient to cover.” Under this authority, the Commission should set the FSR to ensure that customers do not have to pay for unnecessary or unreasonable FSR-related costs.[9] The Commission should reject the Joint IOUs’ attempts to argue that the statute’s use of the phrase “sufficient to cover” means that the Commission has no discretion on the FSR.

Section 394.25(e) does not state that the “bond or insurance” amount must equal or even include the same components as the reentry fee. Instead, the amount must be “sufficient to cover” the reentry fee. In using the phrase “sufficient to cover,” rather than “equal to,” “shall be,” or another phrase that would eliminate any Commission discretion, the Legislature gave the Commission discretion to determine what FSR amount is “sufficient to cover” the unlikely event that sudden CCA dissolution occurs.[10] The Commission can set the FSR in the amount the Commission deems sufficient to ensure against the low risk of a CCA dissolution and the subsequent involuntary return of CCA customers to the IOU.

In an analogous setting, the Commission is considering a proposed decision concerning third-party natural gas procurement service providers known as Core Transport Agents (“CTAs”). The Commission must decide the bond or insurance under Section 983.5(d) that is “sufficient to cover” the reentry fee for CTA customers involuntarily returned to service provided by the incumbent gas utility.[11] The Proposed Decision would allow a CTA to use the

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[9] *Id*.

[10] An administrative agency cannot ignore the common meaning of the words used in a statute. *See* CalCCA Opening Brief, at 4–5; *see, e.g.*, D.16-11-022, mimeo at 189 (“In construing a statute, we must first recognize the plain meaning of the statute and show fidelity to the words the legislature has chosen.”); D.14-06-029, mimeo at 18 (“When construing a statute, the Commission must first look to the words and give them their usual and ordinary meaning.”); D.95-08-056, 1995 Cal. PUC LEXIS 661, at *7 (rejecting party contention that “would mean ignoring the plain language of the statute, and reading language into the statute that is not there” which “[t]he rules of statutory construction do not permit.”).

[11] R.14-03-002, *OIR to Implement Registration of Third Party Natural Gas Procurement Service Providers, Known as “Core Transport Agents,” pursuant to Pub. Util. Code Sections 980–989.5 to Regulate non-rate matters, including Registration Standards, Complaint Resolution Practices, and Minimum Standards of Consumer Protection*, Proposed Decision on Phase Two Issues Regarding Core

financial resources that the Commission requires as proof of financial viability[12] as "sufficient to cover" the reentry fee. Similarly, the Commission should use its broad authority here to determine that a "sufficient" FSR amount must account for the limited risk of a CCA's dissolution to avoid imposing unreasonable and unnecessary costs on the CCA's customers.

III. THE CCA REENTRY FEE SHOULD INCLUDE SIX MONTHS OF INCREMENTAL PROCUREMENT COSTS

The Joint IOUs correctly point out that CalCCA did not provide testimony on the reentry fee determination. However, that does not mean the IOU's proposed calculation of the reentry fee to include one year of incremental procurement costs is an "uncontested" fact.[13] In setting ESP reentry fees under Section 394.25(e), the Commission specifically rejected the IOU proposal to include one year of incremental procurement costs.[14] Consistent with its precedent, as a matter of law, the Commission should set the CCA reentry fee as the one-time administrative costs[15] plus six months of incremental procurement costs associated with a mass reentry of customers.[16]

The CalCCA proposal to include only six months of incremental procurement costs in the reentry fee determination is based on the IOUs' tariffs. Six months of incremental procurement

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Transport Agents (Oct. 6, 2017) ("CTA Proposed Decision"). The CTA Proposed Decision is on the Commission's November 30, 2017 Business Agenda.

[12] *See* Section 981(a)(9). Importantly, the CTA Proposed Decision would set the amount to provide proof of financial viability under this statute at the levels in the financial resources schedule that was previously adopted for ESPs to provide proof of financial viability. *See* CTA Proposed Decision, at 169 (Ordering Paragraph 1.c).

[13] Joint IOUs Opening Brief, at 10.

[14] The Commission required the ESP reentry fee to include eight months of incremental procurement. D.13-01-021, *mimeo* at Appendix 1, at 1–2.

[15] While the main point of contention here is the incremental procurement costs, the Joint IOUs opening brief also raises a point about administrative costs to which CalCCA objects. Joint IOUs suggest that the administrative component of the reentry fees should include actual time and materials. *See* Joint IOUs Opening Brief, at 16. CalCCA disagrees and believes that all administrative fees should be set and limited to encourage IOUs to be cost-effective in their approaches to switching over service.

[16] *See* CalCCA Opening Brief, at 2.

costs corresponds with the six-month advance notice period a voluntarily-returning CCA customer must give an IOU to avoid having to pay a Transition Bundled Service Rate.[17] Presumably, the Commission imposed this requirement on voluntarily-returning customers because it determined the IOU only needs six months to procure whatever resources it needs to serve a returning customer. It should make no difference to the IOU regarding the time it needs to procure resources whether the customer was voluntarily or involuntarily returned.

IV. THE FSR IS AN INSURANCE REQUIREMENT AND THE COMMISSION SHOULD ESTABLISH A REASONABLE OBLIGATION

Section 394.25(e) provides that the FSR serves as a form of "insurance" in the unlikely event that a CCA dissolves. The examples CalCCA discussed in its Opening Brief of the Commission-imposed planning reserve margin and other insurance requirements demonstrate that the Commission commonly establishes insurance requirements that balance the risk of the insured-against event with the costs/burden of such insurance.[18] The Commission generally does <u>not</u> set the insurance amount as a forecast of the worst-case scenario.[19]

The CTA Proposed Decision provides a more recent example of the Commission's balancing approach. The CTA Proposed Decision describes how the Commission, in setting the bond amount, balanced the "risks" related to CTA failure with the "cost of registering as a CTA and operating in a competitive market."[20]

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[17] *See* PG&E Electric Rule 23.L.1.a; SCE Rule 23.L.1; SDG&E Rule 27.L.1.a.

[18] *See* CalCCA Opening Brief, at 5–6.

[19] The manner in which any entity determines a certain insurance amount provides a helpful analogy to demonstrate the need for a balanced approach. For example, the State does not establish the required level of insurance that a driver must obtain based solely on the potential catastrophic harm any driver could cause in an accident. Instead, the State looks at the likelihood of the potential catastrophic harm occurring if an accident occurs, the likelihood of such catastrophic accidents occurring at all, and balances those risks with the costs and burdens to the drivers associated with maintaining car insurance at certain levels in determining what level of insurance it will require that drivers obtain. *See, e.g.*, the Legislative History for Assembly Bill 1010 assembled by LRI History LLC, at 11-12.

[20] CTA Proposed Decision, at 28.

The Commission is being asked here to determine what a CCA and an IOU might otherwise negotiate in a commercial setting. If a CCA negotiated the FSR with an IOU in a manner similar to how two parties might bargain over collateral, the parties would conduct a risk-based assessment to determine the FSR.[21] In order to avoid burdening CCA customers with unnecessary and unreasonable costs, the Commission should conduct such a risk-based assessment here. The Joint IOUs stress that the reentry fee is to ensure that *both* CCA and IOU customers are not harmed if an involuntary return occurs.[22] However, the CCA's indemnification costs are directly borne by CCA customers.[23] The Joint IOU proposal would establish an unreasonably-high insurance level that would impose unreasonable costs on CCA customers. The Joint IOUs ignore the evidentiary record regarding the low risk of sudden CCA dissolution[24] and advocate for a proposal that violates the Section 394.25(e) requirement to avoid imposing unreasonable costs on CCA customers.

V. THE CCA FSR SHOULD NOT INCLUDE AN INCREMENTAL PROCUREMENT COST COMPONENT

Since the FSR is an insurance requirement, in setting the FSR the Commission should balance the risk of sudden CCA dissolution with the burden and costs associated with establishing the FSR. In setting the amount and determining what level of FSR is necessary the Commission should not include an incremental procurement cost component.

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[21] *See* CalCCA Opening Brief, at 6–7.

[22] *See* Joint IOUs Opening Brief, at 2.

[23] The Joint IOUs admit that the "CCA customers may pay for the cost of the FSR as part of their CCA rates." Joint IOU Opening Brief, at 4; *see also id*., at 12 (emphasis added) ("It is unreasonable to conclude – as the CCA parties do – that a robust FSR is not needed because CCA customers will pay the costs either way (as part of their CCA rates to fund the FSR, or as reentry fees in an actual involuntary return)".)

[24] CalCCA/Fulmer, Ex. CCCA-01 (Opening Testimony), at 11, line 1 to 32, line 6.

A. The Likelihood of CCA Dissolution Is Low Because CCAs Are Not Risky Enterprises

The Joint IOUs do not dispute CalCCA's contention that the risk of CCA dissolution is low.[25] Rather, the Joint IOUs focus their argument on the possibility that a CCA *could* fail—that a CCA cannot entirely eliminate the risk of a sudden dissolution.[26] Despite conceding that "these agencies no doubt seek to limit risk,"[27] the Joint IOUs argue the CCA FSR be based on the worst-case scenario, because a CCAs "efforts" to avoid dissolution "could be unsuccessful."[28] This illogical approach to setting a minimum insurance level runs counter to the approach used by the Commission[29] and should not be permitted here. The Commission should set the FSR based on the facts—CCAs are not risky and CCA dissolution is unlikely.

To distinguish the FSR the Commission required for ESPs, the Joint IOUs contend that various "key differences" between ESP and CCA service suggest that CCA customers need *more* consumer protection than ESP customers.[30] In asserting the CCAs are more risky than ESPs, the Joint IOUs ignore the single most significant difference between a CCA and an ESP—a CCA is a local government not-for-profit entity formed to *benefit* its customers and be accountable *directly* to those customers.[31] The notion that CCA customers need more consumer protections than do ESP customers is not supported by the record. Rather, the evidence of the low risk of a

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[25] *See* CalCCA Opening Brief, at 7–11.

[26] Joint IOUs Opening Brief, at 6. ("[T]he Legislature already assessed that some *likelihood* of CCA failure or other service termination exists, and saw fit to require a CCA FSR to protect customers.")

[27] *Id.*, at 17.

[28] *Id*.

[29] *See* CalCCA Opening Brief, at 5–6.

[30] *See* Joint IOUs Opening Brief, at 6–8. The differences include: "opt-out" service, obligation to serve residential customers, service under standard tariff and conditions, and joint power agency structure. The Joint IOUs also point out that Senate Bill ("SB") 350 was not enacted. SB 350 is simply irrelevant to the issue at hand.

[31] *See* CalCCA Opening Brief, at 15–16.

CCA dissolution, when compared to an ESP dissolution, supports the Commission lowering the FSR for CCAs.

An investment-grade credit rating is another proxy to determine that a CCA is not risky. The Joint IOUs suggest that, because a credit rating could change over time, an investment-grade credit rating should not be a proxy for low risk.[32] However, under MCE's proposal, if a credit rating is downgraded below investment grade the CCA could no longer self-insure and would submit an advice letter to update the FSR and provide a Financial Security Instrument ("FSI").[33]

Despite making these tangential arguments about the risk of CCAs relative to ESPs and using credit ratings, the Joint IOUs have not shown that CCAs are risky and therefore CCA dissolution is likely. In determining the level of the FSR to set, the Commission should find that the risk of CCA dissolution is low.

B. The Joint IOUs Overlook the Burden and Costs Associated with a Monthly Adjusted FSR that Accounts for Incremental Procurement Costs

To support their assertion that a monthly-adjusted FSR would not be burdensome, the Joint IOUs claim that CalCCA witness Charles Perl "conceded during hearings that the lengthy [credit procurement] process described in his direct testimony entails *the initial establishment of a credit facility* with a bank, not the simple adjustment of a letter of credit issued under the facility."[34] The Joint IOUs mischaracterize Mr. Perl's testimony. The issue is not whether adjusting a letter of credit is "simple," but whether monthly adjustments are unduly costly or burdensome.

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[32] Joint IOUs Opening Brief, at 19.

[33] MCE Opening Testimony at 6, lines 16–19

[34] Joint IOUs Opening Brief, at 14 (emphasis in original).

Mr. Perl testified that for multiple reasons it would be difficult and costly for a CCA to establish a variable FSI to meet a FSR that fluctuated monthly.[35] First, adjusting a letter of credit[36] ("LOC") is "a very unusual proposition"[37] because it is uncommon "to change one of the business terms of an agreement after you entered into it."[38] As Mr. Perl testified: "[a]n LOC provider would not agree to increase and/or decrease the amount of the LOC on a monthly basis because that LOC provider pledges actual financial resources internally in support of the LOC amount."[39] According to Mr. Perl, "an increase [in the LOC] would require reopening the agreement, with the LOC provider then needing to obtain additional financial resources internally for the increase."[40]

Second, requiring CCAs to adjust LOCs monthly would likely mean that the CCAs must establish and pay the costs associated with LOCs that would far exceed the credit support required to meet the current FSR.[41] A CCA must buy a FSI that is outsized to prepare for any potential incremental procurement risk, and then only use a portion of the FSI.[42] The only alternative would be for a CCA to constantly have to conduct competitive procurements of LOCs monthly, which as discussed previously,[43] is simply not possible.

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[35] CalCCA/Perl, Hearing Transcript, Vol. 16, at 2012, lines 12–19; CalCCA/Perl, Ex. CCCA-02, at 36, line 11 to 40, line 15.

[36] The Joint IOUs have asked the Commission to require CCAs to post cash or LOCs only.

[37] CalCCA/Perl, Hearing Transcript, Vol. 16, at 2014, line 19–25.

[38] *Id.*, at 2014, line 28 to 2015, line 3.

[39] CalCCA/Perl, Ex. CCCA-02, at 38, line 8 to line 10.

[40] *Id.*, line 17 to line 19.

[41] CalCCA/Perl, Hearing Transcript, Vol. 16, at 2022, line 27 to 2024, line 6.

[42] *Id.*, at 2016, line 19 to 2017, line 9. In addition, this "uncertainty or variance from standard [LOC] terms [would] be reflected in the bid received and fee paid" for the LOC by a CCA. CalCCA/Perl, Ex. CCCA-02, at 39, line 3 to line 4.

[43] CalCCA Opening Brief, at 20; CalCCA/Perl, Ex. CCCA-02, at 36, line 11 to 40, line 15.

Third, the Joint IOUs' statements about the low cost of certain types of FSI when compared to their face value[44] and that FSR costs are "simply a cost of doing business that CCAs can and should plan for and pay for" oversimplifies and misstates the financial consequences for CCAs. Any FSI that a CCA must secure to satisfy a FSR with a significant incremental procurement component would grossly exceed the current FSR and result in CCA customers bearing unnecessary costs.

Finally, the Joint IOUs overlook that a monthly adjusted FSR could necessitate revising a FSI in only a few days.[45] The administrative burden and costs associated with such a quick turnaround would be considerable, if not impossible. The Commission has routinely rejected such overly-burdensome processes. The CTA Proposed Decision rejects the bond calculation formulas recommended by the utilities and other parties because they are "too cumbersome to apply, and would require frequent review by the Energy Division to ensure that the CTA has posted financial resources in the applicable amount."[46] Here too, the Commission should reject the Joint IOU proposal to require monthly FSR updates because the Joint IOU proposal would be unnecessarily burdensome and costly.

C. The FSR Should Be Based Only on Administrative Costs Because Administrative Costs Are Certain While Procurement Costs Are Speculative

The Commission should set the FSR at the administrative component of the reentry fee alone because administrative costs are certain to exist and can be assessed using a simple calculation. Procurement costs are by their forward-looking nature going to be speculative. Establishing a FSR based on a projection of hypothetical procurement costs utilizing forecasts

[44] Joint IOUs Opening Brief, at 21–22 (explaining that "[a] creditworthy CCA can expect to pay about 1% of the face value of the FSI" and "a less creditworthy CCA" can expect to pay 2%).

[45] CalCCA Opening Brief, at 20–21; *see also* CalCCA/Perl, Ex. CCCA-02, at 36–40.

[46] CTA Proposed Decision, at 21.

that may not come to bear would unnecessarily impose significant additional costs on CCA customers.[47] In an analogous situation, in the CTA Proposed Decision the Commission would not adopt the proposal that the financial security amount include speculative incremental procurement costs. Instead, the CTA Proposed Decision would have the Commission adopt a schedule that "allows for easy verification by the Energy Division."[48]

If the Commission adopts the Joint IOU proposal that the FSR include incremental procurement costs, the Commission should ensure that a temporary spike in the FSR posting does not itself cause a CCA's failure. The Joint IOU proposal might require CCAs to post FSRs of hundreds of millions of dollars if market prices increased dramatically, even for a short period. Postings of this magnitude would exceed most CCAs' annual revenue.

The Commission should therefore adopt a procedure whereby a CCA can instead request that the Commission limit the FSR by making a showing through a Tier 2 advice letter that the CCA is otherwise financially sound and able to meet its obligations, but needs temporary relief from increases to the FSR. A CCA with an investment grade credit rating should have a rebuttable presumption of being financially sound.

The total FSR would be set at a maximum of five times the administrative cost component for the CCA—if lower than the amount required by the IOU—which the CCA would post when making the filing. The Commission could then order this FSR amount be set for six months, or whatever time period the Commission deemed appropriate, to allow for any temporary spikes in market prices to subside without the increased FSR itself causing a CCA failure. After six months or other appropriate time period, the Commission would reevaluate

[47] *See* CalCCA Opening Brief, at 21–22.
[48] *Id.*, at 21.

whether there is still a need for the increased FSR. If the Commission rejected the CCA filing, the CCA would then post the required FSR.

VI. CALCCA'S PROPOSAL FOR IMPLEMENTATION OF THE FSR IS REASONABLE AND FAIR

A. A CCA Should Calculate the FSR Every Year, or More Frequently as Initiated by the CCA

A CCA should update its FSR once per year, with more frequent updates only required under certain conditions. An annual CCA FSR calculation is appropriate because an FSR set based on the administrative cost component of the reentry fee should not change dramatically from year to year.[49]

Even if the FSR includes incremental procurement costs, the FSR need not be updated more than annually. The Intercontinental Exchange ("ICE")-based forecasts that the IOUs propose to use to determine incremental procurement costs adequately reflect forecasting uncertainties.[50] Therefore, the Joint IOUs argument that a monthly update is needed to eliminate forecasting uncertainties regarding incremental procurement costs should be given little weight.[51] CCAs would update the FSR based on these forecasts annually, and may elect to update the FSR more frequently to account for market corrections that adjust the forecasts.

B. The Proxies Used to Calculate the Administrative Cost Component of the Reentry Fee Should Be the CCA Mass Enrollment Fee and the CCASR Fee

The Commission should base the administrative cost component of the reentry fee on the CCA Mass Enrollment Fee plus an estimate of the number of customers being switched over to

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[49] *See* CalCCA/Fulmer, Ex. CCCA-01, at 38, lines 19–22. If during the annual filing, a CCA's recalculated FSR is within 15% of the FSR currently in place, no change would be necessary to the FSR. Outside the annual advice letter process, if a CCA takes an action such as providing service to a new community that causes its customer count to change by 15% or more, then the FSR should be immediately recalculated and updated with a new advice letter. *Id.*, at lines 4–8.

[50] Since the ICE prices are actual forward prices offered on the exchange, they incorporate similar factors that would be considered in a price forecast.

[51] Joint IOUs Opening Brief, at 13–14.

bundled service multiplied by the tariffed Community Choice Aggregation Service Request ("CCASR") fee.[52] The Joint IOUs oppose this simple and verifiable proposed calculation because it does not account for "off-cycle meter reads, the creation of off-cycle customer bills, and the provision of notification to the impacted customers."[53]

The Joint IOUs' focus on off-cycle components is misguided because involuntary customer returns would be *en masse*, not one-off, off-cycle transfers. The historical example of mass returns from Alternative Retail Electric Suppliers to the incumbent IOU in Chicago demonstrates that involuntary returns of customers can happen in a methodical and orderly manner over a fairly short timescale.[54] The Mass Enrollment Fee and the CCASR provide the proxies for fees associated with a mass enrollment of involuntarily returned CCA customers.

C. Applying a 20-40% Discount to Determine the Forecast of Returned Customers Is Reasonable

The Commission should consider the likelihood that a subset of customers will have already voluntarily returned to bundled IOU service before a CCA dissolution would occur.[55] Applying a discount of 20-40% to determine the forecast of returned customers for the FSR appropriately accounts for voluntary customer returns.[56]

The Joint IOUs attempt to argue against using such a discount by pointing out that CalCCA witness Fulmer explained that little customer attrition from CCAs to IOUs has occurred even when CCA rates have been higher than IOU rates.[57] Mr. Fulmer offered this example to

[52] CalCCA/Fulmer, Ex. CCCA-01, at 35, line 17 to 36, line 18.

[53] Joint IOUs Opening Brief, at 16. The Joint IOUs propose instead that the Commission use the fee for voluntary returns set forth in each IOU's Schedule CCA-SF, which they argue is "designed to recover the incremental administrative costs for individual voluntary returns." *Id.*, at 15.

[54] CalCCA/Waen, Ex. CCCA-02, at 11, lines 11–14.

[55] *See* CalCCA/Fulmer, Ex. CCCA-01, at 32–34.

[56] *See id.,* at 36, lines 2–10; CalCCA/Fulmer, Hearing Transcript, Vol. 15, at 1941, line 5 to 1942, line 3.

[57] *See* Joint IOUs Opening Brief, at 20.

demonstrate that small likelihood of CCA failure. As he testified, *modestly* higher CCA rates led to low customer attrition.[58] But as Mr. Fulmer also pointed out, "a few months of a *modestly* higher" CCA rates is markedly different from the "hypothetical case where there is *significant* rate increases that would potentially drive some amount of customers back to bundled service" that must occur to result in a CCA dissolution.[59]

The Joint IOUs also ask the Commission to reject the proposed discount because Mr. Fulmer described the 20 to 40% discount figure as "somewhat arbitrary" and not supported by "empirical numbers."[60] Mr. Fulmer asserted his professional opinion, based on his expertise, because there has been no actual CCA failure from which he could extrapolate empirical numbers.[61] The Commission should view as credible his testimony concerning the remaining number of CCA customers that would be involuntarily returned to the IOU if a CCA dissolution occurs. Based on that testimony, the Commission should reject the Joint IOU proposal that the FSR calculation be based on 100% of a CCA's existing customer base.

D. Bonds Are a Statutorily-Mandated Instrument to Satisfy the FSR

The Commission should give CCAs the flexibility to satisfy the FSR through posting a bond, and through other manners, including through cash, letters of credit, and restricting assets on a balance sheet.[62] The Joint IOUs inappropriately argue that surety bonds should not be permitted to satisfy the FSR because "collecting on a surety bond is similar to collecting on an insurance claim, where a litigious and delayed process for resolving a claim is not unusual."[63]

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[58] *See* CalCCA/Fulmer, Ex. CCCA-01, at 29, lines 2–7.

[59] CalCCA/Fulmer, Hearing Transcript., Vol. 15, at 1942, line 25 to 1943, line 7.

[60] Joint IOUs Opening Brief, at 20–21.

[61] That there have been no CCA failures in California further illustrates that CCAs are not risky, as discussed in Section V.A. *supra*.

[62] CalCCA Opening Brief, at 17–19.

[63] Joint IOUs Opening Brief, at 22.

The Commission cannot ignore the express statutory language. The Legislature undeniably intended bonds to be available to satisfy the FSR because the statute explicitly allows CCAs to post "a bond."[64] The Commission properly construed that language when the Commission allowed ESPs to post bonds to comply with their FSR requirements.[65] The Joint IOUs provide the Commission with no reason to deviate from this existing Commission practice.

E. CCAs Should Submit the FSR to the Commission, not the IOUs

The Commission should require the CCA FSR to be posted with the Commission. For nearly two decades, the Commission has required ESPs to post their FSR with the Commission as opposed to the IOUs because doing so best serves "customer interests."[66] Customer interests will similarly be better served by requiring CCAs to post their FSR with the Commission. The Joint IOUs provide the Commission no reason to deviate from this existing Commission practice.

F. The Commission Should Net Out Forecasts of Negative Procurement Costs and Accordingly Reduce the FSR

In establishing the ESP FSR, the Commission allowed the negative incremental procurement costs to offset up to 100% of the calculated incremental administrative costs.[67] If the Commission includes an incremental procurement cost component in the CCA FSR, it should similarly reduce the total FSR by any benefit associated with CCA customers returning to the IOU. The Joint IOUs provide the Commission no reason to deviate from this existing Commission practice.

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[64] Pub. Util. Code § 394.25(e). The Legislature also explicitly authorized CCAs to use insurance to meet this requirement, and so the Commission should not give weight to the IOU's argument that insurance-like collection is too burdensome.

[65] D.13-01-021, *mimeo* at 29–30, 35 (Conclusions of Law 1).

[66] *Id.*, *mimeo* at 27–28.

[67] *Id.*, *mimeo* at 31.

Respectfully submitted,

By: /s/ ______________________________

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November 20, 2017

Attorneys for CalCCA

November 20, 2017

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

Advice Letter 28-E

Re: Request for Approval to Shift Funds to Marin Clean Energy's Financing Program

In compliance with California Public Utilities Commission ("Commission") Decision ("D.") 09-09-047, Ordering Paragraph ("OP") 43, filed September 24, 2009, and the Energy Efficiency Policy Manual,[1] Marin Clean Energy ("MCE") submits this filing to request authority to shift funds between MCE's Small Commercial Program and its Financing Program to accommodate anticipated spending for the remainder of 2017.

Effective Date: December 20, 2017

Tier Designation: Tier 2

Pursuant to General Order 96-B, Energy Industry Rule 5.2, this advice letter is submitted with a Tier 2 designation.

Purpose

The purpose of this advice letter filing is to seek approval to shift funds from MCE's Small Commercial Program to its Financing Program to accommodate anticipated spending for the remainder of 2017.

Background

MCE currently administers a Financing Program as part of its Energy Efficiency portfolio. The Financing Program has historically included Single Family, Multifamily, and Commercial On-Bill Repayment ("OBR") components to provide MCE customers with low-cost financing options to complete energy efficiency improvements to their homes or businesses.[2] Currently, MCE's Financing Program supports participation in Property Assessed Clean Energy ("PACE")

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[1] Version 5, July 2013, Section II.7 at p. 13, available at http://www.cpuc.ca.gov/NR/rdonlyres/7E3A4773-6D35-4D21-A7A2-9895C1E04A01/0/EEPolicyManualV5forPDF.pdf.

[2] MCE Single Family, Multifamily, and Small Commercial OBR program closures were approved by the Commission pursuant to MCE Advice Letters 10-E and 24-E.

programs. To better serve ratepayer interests, MCE is analyzing metered energy data to understand the energy savings associated with PACE projects within Marin County. MCE's Financing Program requires additional funding associated with this analysis through 2017.

Financing Program Activity

MCE's PACE analysis work will give MCE insight into PACE project performance and improve MCE's ability to advise and inform current and potential PACE participants. MCE proposes to shift funds into its Financing Program budget to accommodate the PACE analysis because the current Financing Program budget is insufficient to cover the scope of work for this activity through 2017. Some of these funds will be committed to be spent in 2018 because it is anticipated that the contracted activity will continue into 2018.

Fund Shifting for MCE's 2017 Budget

MCE requests authority to shift funds from its Small Commercial Program to its Financing Program to support the Financing Program's expenditures for implementation activities through the end of 2017. MCE's Small Commercial program is anticipated to otherwise have remaining funds at the end of 2017 sufficient to accommodate the proposed fund shift. The proposed fund shift is illustrated in Table 1 below.

Table 1: Requested Fund Shift in MCE's 2017 Budget

Program	2017 Budget	Shift Out	Shift In	New Budget
Small Commercial Energy Efficiency	$937,461[3]	($22,500)		$914,961
Financing	$27,031[4]		$22,500	$49,531
Total	**$964,492**	**($22,500)**	**$22,500**	**$964,492**

Conclusion

MCE requests authorization to shift $22,500 out of MCE's Small Commercial Program and into its Financing Program.

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[3] This Small Commercial Program budget is $5,000 more than the budget reflected in Commission-approved Advice Letter 24-E ($932,461). Subsequent to Commission approval of Advice Letter 24-E, MCE shifted $5,000 into MCE's Small Commercial budget. The fund shift did not trigger the 15% rule. As such, MCE did not file an advice letter.

[4] This is the Financing Program budget pursuant to Commission-approved MCE Advice Letter 24-E.

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:

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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.13-11-005 service list. For changes to this service list, 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 Nathaniel Malcolm at (415) 464-6048 or by electronic mail at nmalcolm@mceCleanEnergy.org.

/s/ Nathaniel Malcolm

Nathaniel Malcolm
Policy Counsel
MARIN CLEAN ENERGY

cc: Service List R.13-11-005, A.17-01-013 *et al*.

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

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

Marin Clean Energy

Utility type:	Nathaniel Malcolm, Policy Counsel, Marin Clean Energy
☑ ELC ☐ GAS	Phone #: 415-464-6048
☐ PLC ☐ HEAT ☐ WATER	E-mail: nmalcolm@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE			(Date Filed/ Received Stamp by CPUC)
ELC = Electric	GAS = Gas		
PLC = Pipeline	HEAT = Heat	WATER = Water	

Advice Letter (AL): 28-E

Subject of AL: Request for Approval to Shift Funds to Marin Clean Energy's Financing Program

Tier Designation: ☐ 1 ☑ 2 ☐ 3

Keywords (choose from CPUC listing):

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other ______________________________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution: N/A

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL No

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: N/A

Resolution Required? ☐ Yes ☑ No

Requested effective date: December 20, 2017 No. of tariff sheets: N/A

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

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

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Ave.,
San Francisco, CA 94102
EDTariffUnit@cpuc.ca.gov

Utility Info (including e-mail)
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Nathaniel Malcolm, Policy Counsel
(415) 464-6048
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[1] Discuss in AL if more space is needed.

Braun Blaising Smith Wynne, P.C.

Attorneys at Law

November 29, 2017

Via Electronic Mail (timothy.sullivan@cpuc.ca.gov)

Mr. Timothy Sullivan
Executive Director
California Public Utilities Commission
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Subject: **Rule 16.6 Request to Defer Deadline For CCA Programs To File Energy Storage Advice Letters**

Dear Mr. Sullivan:

Pursuant to Rule 16.6 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Marin Clean Energy ("MCE"), Sonoma Clean Power ("SCP"), Lancaster Choice Energy ("LCE"), Silicon Valley Clean Power ("SVCP"), and Peninsula Clean Energy ("PCE") (collectively, the "CCA Parties") respectfully request your approval to defer Community Choice Aggregation ("CCA") programs' January 1, 2017 deadline to submit their respective energy storage ("ES") advice letters until at least 45 days after the investor-owned utilities' ("IOU") automatic limiter advice letter is approved by the Commission.

BACKGROUND

Ordering Paragraph 5 of Decision ("D.")13-10-040 requires that each CCA program file a Tier 2 Advice Letter once every two years starting on January 1, 2016 to report its progress in procuring 1% of its 2020 annual peak load from eligible energy storage projects.[1] The next ES advice letter filings are currently due on January 1, 2018.

In D.17-04-039, the Commission modified the CCA programs' ES obligation by adopting an "automatic limiter." The automatic limiter ensures that each CCA program's customers are not subject to a total ES obligation (the sum of the CCA program's 1% ES obligation and any IOU-procured ES resources that the CCA program's customers pay for through distribution rates and non-bypassable charges) that is greater than the ES obligation of the IOU that provides distribution service to that CCA's customers.[2] If a CCA's customers' total ES obligation exceeds the relevant IOU's obligation, the automatic limiter is triggered, reducing the CCA program's 1% ES obligation as needed to bring the respective obligations into alignment.[3]

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1 D.13-10-040 at 77.

2 D.17-04-039 at 68 (Ordering Paragraph 6).

3 *Id.*

In order ensure that CCA programs have adequate information to determine whether their respective 1% ES procurement obligations are reduced by the automatic limiter, Ordering Paragraph 5 of D.17-04-039 instructs the IOUs to:

> . . . make a consolidated compliance filing annually as a Tier 1 Advice Letter through 2020 to update Tables 3-6 based on the most current Community Choice Aggregator and Energy Service Provider load data and utility investment and procurement information, with the first compliance filing due no later than August 1, 2017.[4]

In addition, Ordering Paragraph 6 of D.17-04-039 requires that:

> If the automatic limiter is reached, the consolidated utility compliance filing shall automatically reflect the reduced Community Choice Aggregator / Energy Service Provider energy storage procurement obligation.[5]

On August 1, 2017, the IOUs' filed their consolidated automatic limiter advice letters.[6] Both the CCA Parties and the Alliance for Retail Energy Markets / Direct Access Customer Coalition ("AReM/DACC") protested these advice letters on a number of grounds, including that the advice letters failed to include the most recent data and that the advice letters failed to calculate the automatic limiter, both as required by D.17-04-039.

On November 2, 2017, the Commission distributed Draft Resolution E-4892 ("Draft Resolution"), which, if approved as currently written, will direct the IOUs to submit a supplemental advice letter that: 1) provides current and accurate data for Tables 4-6 relating to direct access storage procurement cost obligations, CCA programs' storage procurement cost obligations, and comparative storage procurement cost obligations; and 2) calculates the automatic limiter.[7] This supplemental advice letter would be due within 30 days of the effective date of the final resolution.[8]

REQUEST FOR EXTENSION

Although the CCA Parties fully support the Draft Resolution, the Draft Resolution does raise a timing problem for CCA programs. In order to submit their biennial ES advice letters, the CCA programs need to know whether, and to what extent, their 1% ES obligations are reduced by the automatic limiter. For this, they need information that was supposed to be provided in the

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4 D.17-04-039 at 67 (Ordering Paragraph 5).

5 D.17-04-039 at 68 (Ordering Paragraph 6).

6 Advice Letter 5119-E (PG&E), 3640-E (SCE), and 3103-E (SDG&E).

7 Draft Resolution at 8-9, 10-11 (Ordering Paragraphs 2-3).

8 *Id.* at 10 (Ordering Paragraph 1)

IOU's August 1 automatic limiter advice letter (namely, the most current and accurate ES information and the automatic limiter calculation).

The Draft Resolution is currently scheduled to be considered at the Commission's December 14 meeting. The corrected advice letters would be due 30 days later. This means that the corrected advice letters will not be available until mid-January, well after the CCA programs' ES advice letters are due. Even if the IOUs were to submit their corrected advice letter prior to the CCA programs' January 1, 2017 deadline, the advice letters would still require Commission review and approval. This would not give the CCA programs adequate time to review the corrected advice letters and adapt their ES procurement plans to the updated information and possible reduced ES obligations.

In order to provide CCA programs with adequate time to develop their ES advice letters, the CCA programs respectfully request that the ES advice letter deadline be extended from January 1, 2017 to 45 days from the date that the corrected automatic limiter advice letters receive final Commission approval. This request is consistent with the timetable set forth in D.17-04-039. Had the IOUs submitted compliant advice letters on August 1, the advice letters likely would have received Energy Division approval no later than October, giving CCA programs ample time to meet their January 1 deadline.

CONCLUSION

The CCA Parties respectfully request that CCA programs' January 1 deadline to submit ES advice letters be extended to 45 days from the date that the IOUs' corrected automatic limiter advice letters receive final Commission approval.

If there are any questions about this request, please contact David Peffer at (916) 326-5813 or by email at peffer@braunlegal.com.

Dated: November 29, 2017

Respectfully submitted,

_______/S/_______

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For:
Marin Clean Energy
Sonoma Clean Power

BB
SW

Lancaster Choice Energy
Silicon Valley Clean Power
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Energy Division Tariff Unit (edtariffunit@cpuc.ca.gov)
Rachel McMahon (rachel.mcmahon@cpuc.ca.gov)
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All Parties of Record for R.15-03-011

December 1, 2017

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

Advice Letter 29-E

Re: Identification of Unspent Funds from Marin Clean Energy's 2017 Energy Efficiency Programs Available for the 2018 Program Budget

Pursuant to Decision ("D.") 14-10-046, *Decision Establishing Energy Efficiency Savings Goals and Approving 2015 Energy Efficiency Programs and Budgets (Concludes Phase I of R.13-11-005)*, Marin Clean Energy ("MCE") submits Advice Letter ("AL") 29-E to identify unspent energy efficiency ("EE") funds for MCE's 2018 EE programs.[1]

Effective Date: December 31, 2017

Tier Designation: This advice filing has a Tier 2 designation pursuant to Ordering Paragraph ("OP") 25 of D.14-10-046, which requires MCE "to file a Tier 2 Advice Letter on December 1, 2014 . . . and on December 1 of each successive year until 2024, identifying carry-forward amounts for the next year."[2]

Purpose

This compliance filing provides the unspent funds amount required by OP 25 of D.14-10-046. This filing also trues-up the estimated 2016 unspent funds to reflect actual spending through the end of 2016. Finally, MCE presents the quarterly electric funds transfers from Pacific Gas and Electric Company ("PG&E") to MCE for the 2018 budget based on offsets calculated using the identified unspent funds.

Background

The funding for EE programs is provided by ratepayers, collected by the Investor Owned Utilities ("IOUs") on authority of the Commission, and subsequently distributed by the IOUs. In MCE's case, PG&E distributes the Commission-approved budget directly to MCE.

[1] D.14-10-046, OP 25 at p. 168.

[2] *Id*. at p. 168.

Pursuant to D.14-10-046, MCE is required to file an annual Tier 2 AL on December 1 that identifies unspent funds that can be carried over into the next program year to reduce the amount of electrical funds PG&E needs to transfer to MCE.[3]

In D.14-10-046, the Commission extended the 2013-2014 annual EE program budgets through 2025.[4] The Commission directed PG&E to transfer EE budgets annually to MCE, less any amount MCE identifies as unspent.[5] Table 1 provides a breakdown of the total 2018 budget by electricity and gas funds including programmatic activities and Evaluation, Measurement, and Verification ("EM&V") activities.

Table 1: 2018 Budget by Electricity and Gas Funds, Including EM&V Funds

	Electricity Funds	**Natural Gas Funds**	**Totals**
Authorized 2018 Program Funds[6]	$1,301,647	$284,700	$1,586,347
Authorized 2018 EM&V Funding[7]	$14,195	$3,262	$18,177
Authorized Budget for 2018	$1,316,562	$287,962	$1,604,524

MCE receives electricity funds and gas funds through separate processes.[8] MCE receives electric EE funds from PG&E on a prospective, quarterly basis.[9] In contrast to the electric funds, MCE invoices PG&E for gas funds on a retrospective, monthly basis.[10] Although MCE's approved annual budget includes both gas and electric funds, MCE does not receive gas funds for which it does not invoice. Therefore under the current rules, unspent (i.e. non-invoiced) gas funds are not included as "unspent" in MCE's annual unspent funds ALs.

[3] *Id*. at p. 168.

[4] *Id*., OP 21 at p. 167.

[5] *Id*. at p. 125; OPs 24-26 at pp. 167-68.

[6] This authorized annual budget includes $1,301,647 in electricity funds and $284,700 in natural gas funds. D.16-05-004, OP 2 at p. 13.

[7] MCE's Annual Budget AL (AL 25-E) and MCE's Supplemental Annual Budget AL (AL 25-E-A) requests the authorized EM&V budget be transferred to MCE, which increases the total 2018 budget by $18,177. MCE will allocate the EM&V funding between electric and gas based on the same proportions as in MCE's underlying annual budgets.

[8] *See* D.14-10-046 at pp. 119-20; OP 24, 26 at pp. 167-68.

[9] D.14-10-046, OP 24 at pp. 167-68.

[10] *Id*. at p. 119; OP 26 at p. 168. In D.14-10-046, the Commission directed PG&E to contract with MCE for the provision of gas funding for MCE's EE gas savings. The monthly invoicing arrangement is embodied in the gas funding contract entered into pursuant to that decision.

True-up of 2016 Unspent Funds

In December 2016, pursuant to D.14-10-046, MCE filed the 2016 Unspent Funds AL.[11] The Commission has recognized that because of the December 1 filing requirement, MCE would have to base the unspent funds on a projection of spending for the year.[12] The Commission suggested MCE "use its best estimates for the months for which it does not yet have actual spending data."[13] As such, as part of this annual advice letter, MCE provides a true-up of the 2016 unspent funds to reflect actual spending through the end of 2016.

Table 2 provides a true-up of the 2016 unspent funds calculation to reflect MCE's actual spending through the end of 2016.

Table 2: True-up of 2016 Unspent Funds Available for Carryover

Actual 2016 Unspent Funds (Electric Only)	Projected 2016 Unspent Funds Reported in MCE AL 21-E (used to off-set 2017 funds)	2016 Committed Funds (Electric Only)	2016 Unspent Funds Available to Off-set 2018 Funds
$416,165	($3,714)	($189,268)[14]	$223,183

The true-up of unspent funds from 2016 results in $223,183 in unspent funds from 2016 available to offset the 2018 budget transfers from PG&E to MCE.

Identification of 2017 Unspent Funds Available for Carryover to 2018

The total unspent EE funds from 2017 available for MCE's 2018 EE program is $195,574 as provided in Table 3 below.[15]

Because this filing is made before the end of 2017, it includes a projection of 2017 program expenditures. As Table 2 illustrates, above, the trued-up 2016 spending results in $223,183 in additional unspent funds from 2016 that will be carried over to off-set the 2018 budget. Table 3, below, provides the total unspent funds from 2016 and 2017 available for carryover to offset the

[11] MCE AL 21-E.

[12] D.14-10-046 at p. 126.

[13] *Id*. at p. 126.

[14] Pursuant to D.12-11-015 at p. 95, the Commission held that committed funds are not considered unspent.

[15] As of this filing, MCE is awaiting disposition of MCE AL 28-E, which requested authority to shift funds between MCE's Small Commercial Program and its Financing Program. For the sake of simplicity, this filing presumes Commission staff approval of MCE AL 28-E. This AL can be updated with supplemental materials if directed by Commission staff or if any of these pending dispositions impact the figures included in this AL.

2018 budget transfers from PG&E. Finally, Table 4, below, provides the quarterly electric payments PG&E will transfer to MCE for the 2018 budget, which factors in the carryover amount from Table 3.

Table 3: Identified Unspent EE Funds Available for Carryover to 2017

2016 Unspent Funds True Up	2017 Unspent Electric Funds	2017 Unspent Gas Funds	Total Unspent Funds Available for Carryover
$223,183	$195,574	N/A[16]	$418,757

Table 4: Electricity Funds Payment Schedule

2018 Electric Budget	Unspent Funds Available for Carryover	2018 Electric Budget Less Carryover	2018 Quarterly Electric Payments
$1,316,562	($418,757)	$897,805	**$224,451**

According to current Commission directive, MCE will continue to invoice PG&E on a retrospective, monthly basis for any gas expenditures incurred in 2018.

Conclusion

MCE identifies a total of $418,757 in unspent funds available to offset the 2018 budget transfers from PG&E. MCE also provides the quarterly electric payments for 2018 in the amount of $224,451 based on the unspent funds.

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, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

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

[16] As stated above, the total unspent EE funds available for carryover excludes unspent gas funds.

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

Nathaniel Malcolm
Policy Counsel
Marin Clean Energy
1125 Tamalpais Ave.
San Rafael, CA 94901
Phone: (415) 464-6048
Facsimile: (415) 459-8095
nmalcolm@mceCleanEnergy.org

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Manager of Policy and Planning, Customer Programs
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1125 Tamalpais Ave.
San Rafael, CA 94901
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astover@mceCleanEnergy.org

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.13-11-005 and A.17-01-013 et al service lists. 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 Nathaniel Malcolm at (415) 464-6048 or by electronic mail at nmalcolm@mceCleanEnergy.org.

/s/ Nathaniel Malcolm

Nathaniel Malcolm
Policy Counsel
MARIN CLEAN ENERGY

cc: Service Lists: R.13-11-005; A17-01-013, *et al*.

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY LSE (Attach additional pages as needed)	
Company name/CPUC Utility No. Marin Clean Energy	
Utility type: ☑ ELC ☐ GAS ☐ PLC ☐ HEAT ☐ WATER	Contact Person for questions and approval letters: Nathaniel Malcolm Phone #: (415) 464-6048 E-mail: nmalcolm@mcecleanenergy.org
EXPLANATION OF UTILITY TYPE ELC = Electric GAS = Gas PLC = Pipeline HEAT = Heat WATER = Water	(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: MCE 29-E

Subject of AL: Identification of Unspent Funds from Marin Clean Energy's 2017 Energy Efficiency Programs Available for the 2018 Program Budget

Tier Designation: ☐ 1 ☑ 2 ☐ 3

Keywords (choose from CPUC listing): Compliance

AL filing type: ☐ Monthly ☐ Quarterly ☑ Annual ☐ One-Time ☐ Other ______________________________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution: D.14-10-046

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: n/a

Resolution Required? ☐ Yes ☑ No

Requested effective date: December 31, 2017 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]:

Pending advice letters that revise the same tariff sheets: none

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

CPUC, Energy Division	**Utility Info (including e-mail)**
Attention: Tariff Unit	**Marin Clean Energy**
505 Van Ness Ave.	**Nathaniel Malcolm, Policy Counsel**
San Francisco, CA 94102	**1125 Tamalpais Ave. San Rafael, CA 94901**
EDTariffUnit@cpuc.ca.gov	**nmalcolm@mcecleanenergy.org**

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	))))))	Rulemaking 15-02-020 (Filed February 26, 2015)

COMMENTS OF LANCASTER CHOICE ENERGY, MARIN CLEAN ENERGY, REDWOOD COAST ENERGY AUTHORITY, SILICON VALLEY CLEAN ENERGY AUTHORITY, AND SONOMA CLEAN POWER AUTHORITY ON THE PROPOSED DECISION ACCEPTING DRAFT 2017 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

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Dated: December 4, 2017

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

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	)	Rulemaking 15-02-020 (Filed February 26, 2015)

COMMENTS OF LANCASTER CHOICE ENERGY, MARIN CLEAN ENERGY, REDWOOD COAST ENERGY AUTHORITY, SILICON VALLEY CLEAN ENERGY AUTHORITY, AND SONOMA CLEAN POWER AUTHORITY ON THE PROPOSED DECISION ACCEPTING DRAFT 2017 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

I. INTRODUCTION

Pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Lancaster Choice Energy, Marin Clean Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority (collectively, "CCA Parties") hereby provide these comments on the *Proposed Decision of Administrative Law Judges Mason, Simon, and Atamturk Accepting Draft 2017 Renewables Portfolio Standard Procurement Plans* ("Proposed Decision"), dated November 14, 2017.

II. COMMENTS

A. The Proposed Decision Should Extend PG&E's and SCE's Solicitation Authorizations from 5 Years to the 10 Years.

The Proposed Decision approves the request of Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas & Electric Company ("SDG&E") (collectively, "IOUs") to forgo holding a 2017 Renewables Portfolio

Standard ("RPS") solicitation, and authorizes the IOUs to sell excess RPS volumes.[1] SDG&E is permitted to conduct solicitations for the sale of RPS volumes for durations greater than 5 years.[2] For PG&E and SCE, the Proposed Decision authorizes solicitations for short-term contracts of 5 years or under, and also authorizes bilateral transactions established in Decision ("D.") 09-06-050. D.09-06-050 is permissive of long-term contracts and states the principle that long-term bilateral contracts "should be reviewed according to the same processes and standards and contracts that come through a solicitation."[3] Given D.09-06-050's permissiveness of long-term contracting, and SDG&E's ability under the Proposed Decision to conduct solicitations for greater than 5 years, the CCA Parties request that PG&E's and SCE's 5-year solicitation authorization be expressly extended to 10 years. The extension to 10 years is important because it will allow IOUs to sell off unneeded energy on terms long enough to allow other load serving entities to meet the 65% long-term contracting requirement specified in Senate Bill ("SB") 350. As noted in the Proposed Decision, the IOUs may need to sell excess volumes due to a variety of reasons.[4] A successful solicitation is an important component of managing excess volumes, and PG&E and SCE should have the same flexibility granted to SDG&E to allow the sale of volumes on terms sufficient to meet SB 350's long-term contracting requirement.

B. Launching CCA Programs Should Have Time to Prepare Procurement Plans Consistent with What the Commission Has Granted Existing Retail Sellers.

With respect to the filing of RPS plans, the Proposed Decision specifically references three CCA programs. The Proposed Decision states that "San Jacinto, Monterey, and Valley

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1 Proposed Decision at 2.
2 *Id.* at 56.
3 *Id.* at 29, 43.
4 *See id*. at 14-15, 26 (referencing PG&E and SCE's statements concerning resource needs and the sales of excess volumes in 2018).

Clean [Energy]" must file their RPS plans upon registering with the Commission or 90 days prior to delivering load, "whichever event comes first."[5] The Proposed Decision also generally references other CCA programs, stating that "CCAs [Community Choice Aggregators]" must file their RPS plans upon registering with the Commission, or 90 days prior to serving load, whichever event occurs first.[6] As drafted, multiple launching CCAs could fall within the plan submittal window on the date of the Proposed Decision's adoption or issuance.[7] The CCA Parties suggest adding a period of 35 days from the date of a decision's issuance for the proposed filing requirements to take effect. The May 26, 2017 Ruling ("Ruling") in this proceeding allowed existing retail sellers 35 days to prepare their respective 2017 RPS Plans,[8] and a launching CCA program should be provided the same opportunity to prepare plans afforded to existing sellers in operation.

The CCA Parties note that the same Ruling states that Electric Service Providers ("ESPs") file RPS plans "when they begin serving retail customers" rather than at registration or 90 days before delivering load.[9] The Ruling's filing requirement for ESPs more closely aligns with the language in SB 350, which requires "other retail sellers to prepare and submit" procurement plans,[10] where retail seller is defined to include a CCA or ESP "*engaged* in the retail sale of electricity to end use customers …"[11] Thus, the CCA Parties suggest that the Commission consider the date of retail service as the plan filing deadline and that, at a minimum,

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5 *Id.* at 63.
6 *Id.* at 5.
7 For example, the CCA Parties understand that Los Angeles Community Choice Energy Authority's ("LACCE") CCA implementation plan has been certified, and that LACCE plans to begin providing service in February 2018.
8 Ruling at Attachment A (there are 35 days between when Ruling was issued and the date by which RPS Procurement Plan filings are due under the Ruling).
9 *Id.* at Attachment B.
10 Cal. Pub. Util. Code § 399.13(a)(1).
11 *Id.* § 399.12(j)(emphasis added).

the plan filing requirements in the Proposed Decision not take effect until 35 days from the date of the adopted decision's issuance.

III. PROPOSED CHANGES

In accordance with Rule 14.3(c), and in light of the discussion above, the CCA Parties request that the following changes be made to the Proposed Decision (with strikethroughs showing removals and italics showing additions):

Page 5	Per the comments filed in this proceeding, *effective 35 days from this decision's issuance,* CCAs must file their RPS plans *within 35 days of registration by* ~~upon registering with~~ the Commission or 90 days prior to serving load, whichever event occurs first.
Page 53	PG&E is authorized to conduct solicitations for the ~~short-term, meaning 5 years or less,~~ sales of RPS volumes *for* 10 *years or less* during the timeframe covered by its 2017 RPS Plan.
Page 54	SCE is authorized to conduct solicitations for the ~~short-term, meaning 5 years or less,~~ sales of RPS volumes *for 10 years or less* during the timeframe covered by its 2017 RPS Plan.
Page 63 (Order 4)	~~For~~ *Effective 35 days from this decision's issuance,* San Jacinto, Monterey, and Valley Clean, t~~hey~~ must file their RPS plans ~~upon~~ *within 35 days of registration by* ~~registering with~~ the Commission or 90 days prior to delivering load, whichever event occurs first.
Page 64 (Order 7)	PG&E is authorized to conduct solicitations for ~~the short-term, meaning 5 years or less,~~ sales of RPS volumes *for* 10 *years or less* during the timeframe covered by its 2017 RPS Procurement Plan, or prior to the Commission issuing a decision on the 2018 RPS Procurement Plans.
Page 65 (Order 8)	SCE is authorized to conduct solicitations for ~~the short-term, meaning 5 years or less~~, sales of RPS volumes *for* 10 *years or less* during the timeframe covered by its 2017 RPS Procurement Plan, or prior to the Commission issuing a decision on the 2018 RPS Procurement Plans.

IV. CONCLUSION

The CCA Parties thank the Commission for the opportunity to provide these comments in this proceeding.

Dated: December 4, 2017

Respectfully submitted,

/s/ Dan Griffiths
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VERIFICATION

I, Dan Griffiths, am authorized to make this Verification under Rules 1.8(d) and 1.11(d) on behalf of the Lancaster Choice Energy, Marin Clean Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy Authority and Sonoma Clean Power Authority, who are absent from the County of Sacramento, California, where I have my office. I declare under penalty of perjury that the statements in the foregoing COMMENTS OF LANCASTER CHOICE ENERGY, MARIN CLEAN ENERGY, REDWOOD COAST ENERGY AUTHORITY, SILICON VALLEY CLEAN ENERGY AUTHORITY, AND SONOMA CLEAN POWER AUTHORITY ON THE PROPOSED DECISION ACCEPTING DRAFT 2017 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

Executed on December 4, 2017, at Sacramento, California.

/s/ Dan Griffiths

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
And Related Matters	Application 17-01-014 Application 17-01-015 Application 17-01-016 Application 17-01-017

COMMENTS OF MARIN CLEAN ENERGY AND THE SAN FRANCISCO BAY AREA REGIONAL ENERGY NETWORK ON PROPOSED DECISION ADDRESSING THIRD PARTY SOLICITATION PROCESS FOR ENERGY EFFICIENCY PROGRAMS

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December 4, 2017

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OF THE STATE OF CALIFORNIA

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Pursuant to California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Rule 14.3, Marin Clean Energy ("MCE") and the Association of Bay Area Governments ("ABAG"), on behalf of the San Francisco Bay Area Regional Energy Network ("BayREN"), submit the following comments in response to the Administrative Law Judge's ("ALJ") *Proposed Decision Addressing Third Party Solicitation Process for Energy Efficiency Programs* ("Proposed Decision") filed on November 13, 2017.

I. Introduction

The Proposed Decision sets forth a thoughtful solicitation process, applicable to Investor Owned Utility ("IOU") Program Administrators ("PAs"), to facilitate the outsourcing of at least 60 percent of energy efficiency ("EE") portfolios to third parties by the end of 2022.[1] This

[1] Decision Addressing Third Party Solicitation Process for Energy Efficiency Programs ("Proposed Decision"), filed on November 13, 2017, at p. 30.

transition represents a positive first step towards a streamlined process designed to effectuate the intent, and meet the requirements of, third party outsourcing set forth in Decision ("D.") 16-08-019. The Commission should approve the process laid out in the Proposed Decision with the following two modifications and one clarification: (1) to address overlap, the Commission should modify the Proposed Decision to direct IOU PAs to include a standard contract term to require coordination among third party providers and other non-IOU PAs operating in the same area; (2) the Commission should modify the Proposed Decision to direct the IOU PAs to require third parties to address program overlap in a coordination plan presented as a component of the third party bids; and (3) the Commission should clarify that the business plan will be approved for a ten-year period.

II. The Commission Should Approve the Third Party Solicitation Process Contained in the Proposed Decision for all Investor Owned Utility Program Administrators.

Greater utilization of third parties to design and implement EE programs allows PAs to focus on overall portfolio design and management. The transition to third party design and implementation will also better utilize market expertise in the private sector.[2] The Proposed Decision's solicitation process includes important oversight protections and encourages transparency and collaboration among PAs. Although the Proposed Decision is a significant step in the right direction, MCE and BayREN recommend that the Proposed Decision be slightly modified to more explicitly require coordination among PAs and third party implementers to address overlapping EE programs.

[2] Proposed Decision at p. 28 (citing, Decision Providing Guidance for Initial Energy Efficiency Rolling Portfolio Business Plan Filings ("D.16-08-019"), filed on August 25, 2016, at pp. 71-72).

Consistent with D.16-08-019, MCE and BayREN agree that the terms of the Proposed Decision apply only to IOU PAs.[3] Nevertheless, because we see value in utilizing private market expertise for program design and implementation, MCE and BayREN intend to voluntarily comply with the spirit of the third party solicitation process.

As noted throughout this docket, MCE has an obligation to pursue cost effective EE programs to meet its customer's procurement needs.[4] As a CCA, MCE is "solely responsible for all generation procurement activities" on behalf of its customers.[5] Moreover, California law requires that a provider "shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."[6] The Commission's EE Policy Manual and the State of California Energy Action Plan similarly define EE and Demand Response as procurement resources that should be utilized at the top of a provider's loading order, prior to acquiring renewable or conventional energy resources.[7] Utilizing the private market for EE programming will be critical to MCE in serving its customers and meeting internal and state policy objectives.

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3 Proposed Decision at p. 42.

4 Final Reply Comments of Marin Clean Energy on Energy Efficiency Business Plans ("MCE Final Reply Comments"), filed on October 13, 2017, at p. 5 (*citing,* Decision Enabling Community Choice Aggregators to Administer Energy Efficiency Programs ("D.14-01-033"), filed on January 23, 2014, Ordering Paragraph 3, at p. 50 (Applying IOU cost- effectiveness standards to CCAs); and Decision Establishing Energy Efficiency Savings Goals and Approving 2015 Energy Efficiency Programs and Budgets ("D.14-10-046"), filed on October 24, 2014, at pp. 109-110 (Setting a TRC ratio of 1.25 for IOUs and CCAs)).

5 Cal. Pub. Util. Code § 366.2(a)(5).

6 Cal. Pub. Util. Code § 454.5(b)(9)(C).

7 Commission, Energy Efficiency Policy Manual, Version 5, July 2013 ("EE Policy Manual"), at p. 1 available at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/EEPolicyManualV5forPDF.pdf.

III. To Address Program Overlap, the Commission Should Modify the Proposed Decision to Direct Program Administrators to Include a Standard Contract Term Requiring Coordination Among Program Administrators.

In D.14-01-033, the Commission explicitly authorized Community Choice Aggregators ("CCAs") to design and administer programs that overlap with legacy IOU programs.[8] In doing so, the Commission acknowledged that "there are obvious practical implications" to CCA PAs, such as how to deal with overlap between IOU and CCA EE programs.[9] As such, the Commission committed to "address these issues when and if they arise in the context of particular programs and applications/advice letters …."[10] MCE's business plan application is the first time since D.14-01-033 that the issue of overlap has been formally raised. It is therefore critical that the Commission address overlap in this proceeding. Given the timing and scope of the Proposed Decision, the first step to addressing program overlap is to ensure that coordination among PAs and third parties is adequately accounted for early in the third party solicitation process.

A. It Is Factual and Legal Error for the Commission to Not Provide Concrete Requirements to Address Program Overlap.

The Proposed Decision agrees with MCE "that coordination among all PAs about solicitations…should be encouraged."[11] Yet, the Proposed Decision fails to provide any concrete requirements to ensure program overlap is adequately addressed at the outset of the solicitation process. This amounts to both legal and factual error that must be addressed in the Commission's final decision.

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8 "If CCAs want to undertake regional or statewide programs…we see no prohibition on their doing so in Section 381.1. There are obvious practical implications…including whether and how to deal with overlap between an IOU and CCA offering." D.14-01-033 at p. 36. *See also* D.14-10-046 at p. 120 (clarifying that the same rules apply to gas funding).

9 D.14-01-033 at p. 36.

10 D.14-01-033 at p. 36.

11 Proposed Decision at p. 43.

Establishing concrete rules around program overlap at the outset would obviate the need to address and correct negative outcomes after PAs and implementers have settled on program design and implementation. The Proposed Decision already requires utilities to develop, and submit for Commission approval, a motion in this proceeding for approval of a standard contract that includes a number of standard contract terms within 45 days of the issuance of the final decision.[12] To properly address program overlap, the Commission should also require IOU PAs to develop and submit for approval a standard contract term to explicitly anticipate and account for program overlap. This standard term would require each winning bidder to coordinate with other PAs in the same region on marketing, outreach, and implementation.[13]

Once IOU PAs file their motions for approval of standard contract terms, MCE, BayREN, and other stakeholders should have the opportunity to respond and provide input on specific language. The standard term does not need to be complex, but must ensure that some communication with overlapping PAs is required. At a minimum, the standard term should include a description of all PAs operating in the IOU's service territory and specifically reference any rules or directives that the Commission ultimately approves (e.g., MCE's proposed downstream liaison role if approved).[14]

As noted above, the Commission has already stated its intent to address program overlap in this proceeding,[15] but will not do so until a subsequent decision addressing business plan

[12] Proposed Decision at p. 38 and p. 52.
[13] Final Comments of Marin Clean Energy on Energy Efficiency Business Plans ("Final Comments on EE Business Plans"), filed on September 25, 2017, at p. 23 (citing, MCE Attachment B Answers at p. 10).
[14] Comments of Marin Clean Energy on Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge ("MCE Comments on Scoping Memo Attachment B"), filed on June 22, 2017, at pp. 9-10.
[15] D.14-01-033 at p. 36.

approvals. As such, utilities will also need to update the PA and third party coordination standard term after the Commission issues its final decision. The Proposed Decision should therefore also be modified to make clear that utility PAs are required to update their standard terms to comply with the Commission's final rules or directives.

B. Requiring an Explicit Coordination Contract Term Would Avoid Anticipated Negative Outcomes Resulting from Program Overlap.

Early coordination among overlapping PA programs is necessary to avoid negative outcomes such as potential "double dipping" of overlapping programs. For example, MCE recently evaluated offering a Smart Thermostat rebate in its multifamily program. However, after performing its due diligence, MCE discovered that Pacific Gas & Electric Company ("PG&E") had an overlapping Smart Thermostat program that used an online form that customers could mail in to receive a rebate. As such, MCE changed course to avoid a situation where customers received rebates from both MCE and PG&E for the same Smart Thermostat. However, if a utility's third party implementer were managing a program that overlapped with another PA's program and the third party failed to discover the overlap, it could create a situation where customers could apply for and receive two rebates for the same activity. Such an outcome would erode precious EE funds and diminish the cost effectiveness of both portfolios. Requiring coordination with other local PAs prior to marketing, outreach, and implementation through the standard contract term would prevent this situation.

Similarly, requiring coordination as a standard contract term would make third party-run utility programs more effective by preventing implementer and customer confusion. For example, an implementer recently inquired what parts of MCE's service territory overlapped with PG&E's, not realizing that MCE's entire service area overlaps with PG&E. While this particular implementer took the initiative to inquire, some may not. A standard contract term ensures that there is a minimum foundation of understanding among EE providers in the same area. Requiring this minimum level of coordination prior to customer outreach will also help to avoid customer confusion by allowing PAs and third parties to craft marketing campaigns that properly account for overlap.

IV. The Commission Should Modify the Proposed Decision to Direct that Investor Owned Utility Third Party Solicitations Include a Requirement that a Bidder Address Overlap in a Coordination Plan Presented as Part of Its Bid.

In addition to requiring a standard contract term to address overlap, the Proposed Decision should be modified to clearly direct utilities to require third parties to include a coordination plan within their bids that addresses overlap with other PAs operating in the same region. MCE proposed this approach as part of its proposal to address overlap in earlier comments.[16] PG&E opposed this suggestion claiming it called for third parties to speculate about MCE's offerings.[17] This concern is unfounded. By the time PG&E conducts the solicitations, the business plans should be approved and publicly available. The business plans will provide sufficient information for bidders to address at a high-level the (1) potential for duplication; (2) coordination of marketing and outreach; and (3) coordination of implementation.[18] Because the Proposed Decision does not rule on ultimate business plan approvals, the final decision should incorporate this coordination requirement to achieve the Commission's intent to address any potential program overlap.

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[16] MCE Comments on Scoping Memo Attachment B at p. 9; MCE Final Comments on EE Business Plans at pp. 22-23; MCE Final Reply Comments on EE Business Plans at p. 14; Joint Comments of Marin Clean Energy and the San Francisco Bay Area Regional Energy Network on Third Party Solicitation Proposals ("MCE and BayREN Comments on Solicitation Proposals"), filed on August 18, 2017, at p. 4.

[17] Pacific Gas & Electric Company's (U 39 M) Opening Comments on the Energy Efficiency Business Plans ("PG&E Opening Comments"), filed on September 25, 2017, at p. 25.

[18] MCE Comments on Scoping Memo Attachment B at pp. 9-10.

V. The Commission Should Clarify that the Business Plan Period is Ten Years.

The Proposed Decision indicates that D.16-08-019 directed IOU PAs, MCE, and Regional Energy Networks ("RENs") to file business plans by January 15, 2017 *for the 2018-2025 timeframe*.[19] However, D.16-08-019 contains no direction that business plans should be proposed for that particular time period. It is correct that some PAs, including PG&E, specifically requested approval of their individual business plans for the 2018-2025 time periods.[20] While the Commission has discretion to approve or deny such requests, the Commission has previously expressed that business plans typically cover a ten-year period absent a trigger event.

In D.15-10-028, the Commission stated "EE funding is in place for ten years."[21] The Commission further explained that after a PA's initial business plan filing, it "*must* file revised business plans only when a 'trigger' event happens…Business plan filings will generally be untethered to the calendar except that PAs will need to apply for an extension of funding – that is, *a restarting of the ten-year clock* -- no less than one year before funding is set to end."[22]

Because some PAs have relied on the rolling portfolio process explained in D.15-10-028 that contemplates a default ten-year period, the Commission should clarify that approval of business plans in this proceeding is not necessarily limited to the 2018-2025 time period.

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[19] Proposed Decision at p. 3 and p. 29. (Emphasis added).

[20] Application of Pacific Gas & Electric Company for Approval of 2018-2025 Rolling Portfolio Energy Efficiency Business Plan and Budget (U39M) ("Application 17-01-015"), filed on January 17, 2017.

[21] Decision re Energy Efficiency Goals for 2016 and Beyond and Energy Efficiency Rolling Portfolio Mechanics ("D.15-10-028"), filed on October 28, 2015, at p. 57.

[22] D.15-10-028 at p. 46. (Emphasis added); *See also*, p. 55 ("the business plans are to provide *general* information on the expected levels of annual spending for the duration of the business plan (i.e., "under the business plan, we expect spending to be $X per year for up to ten years"). (Emphasis in original).

VI. Conclusion

MCE and BayREN thank Commissioner Peterman, Administrative Law Judge Fitch, and Administrative Law Judge Kao for their thoughtful consideration of these comments.

Respectfully submitted,

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Appendix A

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, Marin Clean Energy and the San Francisco Bay Area Regional Energy Network offer the following index of recommended changes to the *Decision Addressing Third Party Solicitation Process for Energy Efficiency Programs*, including proposed changes to the Findings of Fact, Conclusions of Law and Ordering Paragraphs.

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The structure we adopt is for the utilities to submit results to the Commission for approval at one point during the solicitation process, but covering two distinct items. The utilities will be required to submit the results of their RFA process, confidentially identifying all of the bidders, along with the recommended shortlisted bidders and rationale or bid evaluation criteria utilized. At the same time, the proposed RFP itself, along with its evaluation criteria, shall be submitted. <u>In order to address potential overlap among PA portfolios, the RFP must include a request for bidders to submit a coordination plan to address overlap as part of its bid and the evaluation criteria must address how the utilities will evaluate such coordination plans.</u> These items will be required to be submitted via a Tier 2 advice letter, for all third party solicitations.

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Some of the terms that we expect to be standard, at least for similar program types, are the following:

- Eligibility (type of business, license requirements, insurance and bonding requirements, etc.)
- Safety requirements
- Workforce qualifications and quality installation requirements
- Progress and evaluation metrics
- Contract term/length
- Diverse and disadvantaged business and employee terms, including small businesses, if applicable
- Payment schedule and terms, both to third party and to participating utility customers (for incentive payments)
- Data collection and ownership requirements
- EM&V requirements, including guidelines about normalized metered energy consumption (NMEC) design requirements
- Dispute resolution process
- Termination process
- <u>Coordination with other program administrators</u>.

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Each utility shall submit that proposed standard third party contract as a motion for standard contract approval within this business plan application proceeding within 45 days after this decision is issued. <u>Once the Commission issues a final decision on business plan approval, utilities may be required to update standard contract terms to comply with that decision. The Commission</u>

will provide more specific direction on the timing of any required revisions when it issues such a decision.

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We agree with the comments of MCE that coordination among all PAs about solicitations, including all of the IOUs, as well as the RENs and MCE, should be encouraged. We do not require, however, that the RFA shortlist results be shared among PAs. Doing so may not only be impractical, but also may violate expectations of confidentiality on the part of bidders and it is not clear what benefits would override those considerations. Each PA is ultimately responsible for its own solicitation process, while as much informal communication and coordination among the PAs as possible is encouraged. Instead, to address potential overlap and as noted above, we will require utility PAs to request coordination plans from all third party bidders through RFPs and will require the filing of a standard contract term that requires third parties to coordinate with other PAs in the same geographical area.

Findings of Fact

21. The emergence of non-utility program administrators creates a potential for energy efficiency program overlap. Avoiding potential negative outcomes resulting from program overlap can be achieved through coordination among program administrators and third parties.

Conclusions of Law

21. In D.14-01-033, the Commission explicitly authorized Community Choice Aggregators to design and administer programs that overlap with legacy utility programs. All program administrators, including but not limited to the utility PAs, should be encouraged to coordinate and share information on third party solicitations. To further address overlap, utility administrators should be required to include standard contract language requiring third parties to coordinate with other program administrators in the same geographical area. Further, utility requests for proposals should request that third party bidders provide coordination plans as part of their bids. ~~but s~~Sharing of confidential short lists should not be required.

Ordering Paragraph 2

2. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Southern California Gas Company shall file a Tier 2 advice letter for each third party solicitation, or a batch of third party solicitations, containing the recommended short list(s) from the request for abstract stage based on the evaluation criteria used, as well as the proposed request for proposal(s) including evaluation criteria planned, for Commission review. Each proposed request for proposal(s) shall include a requirement that bidders provide a coordination plan to address potential overlap with other PAs in the same geographical area. Similarly, proposed evaluation criteria must address how utilities will evaluate such coordination

plans.

Ordering Paragraph 5

5. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Southern California Gas Company shall, within 45 days of the issuance of this decision, each file a motion in this proceeding for approval of a standard contract for third parties, with terms and conditions that address at least the following areas:

a. Eligibility (type of business, license requirements, insurance and bonding requirements, etc.)
b. Safety requirements
c. Workforce qualifications and quality installation requirements
d. Progress and evaluation metrics
e. Contract term/length
f. Diverse and disadvantaged business and employee terms, including small businesses, if applicable
g. Payment schedule and terms, both to third party and to participating utility customers (for incentive payments)
h. Payment provisions for pay-for-performance arrangements
i. Data collection and ownership requirements
j. Evaluation, measurement, and verification requirements, including guidelines about normalized metered energy consumption design requirements
k. Dispute resolution process
l. Termination process
m. Coordination with other program administrators.

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REPLY COMMENTS OF MARIN CLEAN ENERGY AND THE ASSOCIATION OF BAY AREA GOVERNMENTS ON PROPOSED DECISION ADDRESSING THIRD PARTY SOLICITATION PROCESS FOR ENERGY EFFICIENCY PROGRAMS

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December 11, 2017

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REPLY COMMENTS OF MARIN CLEAN ENERGY AND THE ASSOCIATION OF BAY AREA GOVERNMENTS ON PROPOSED DECISION ADDRESSING THIRD PARTY SOLICITATION PROCESS FOR ENERGY EFFICIENCY PROGRAMS

I. INTRODUCTION

Pursuant to California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Rule 14.3, Marin Clean Energy ("MCE") and the Association of Bay Area Governments, on behalf of the San Francisco Bay Area Regional Energy Network ("BayREN") submit this reply to comments filed December 4, 2017 regarding the Administrative Law Judge's ("ALJ") *Proposed Decision Addressing Third Party Solicitation Process for Energy Efficiency Programs* ("Proposed Decision").

Specifically, MCE and BayREN reply to Pacific Gas and Electric Company's ("PG&E") comments on the Proposed Decision. The Commission should not adopt PG&E's request to delay Community Choice Aggregator ("CCA") and Regional Energy Network ("REN") Program Administrator ("PA") solicitations for new programs. Adoption of this proposal is contrary to Decision ("D.") 12-11-015 and D.16-08-019 and would: (1) undermine local, non-Investor Owned Utility ("IOU") PA programmatic activities; (2) unreasonably delay CCA and REN program design and implementation; and (3) impair MCE's ability to administer a cost effective energy efficiency ("EE") portfolio.

II. THE COMMISSION SHOULD REJECT PG&E'S REQUEST TO DELAY NEW PROGRAM SOLICITATIONS BY COMMUNITY CHOICE AGGREGATOR AND RENEWABLE ENERGY NETWORK PROGRAM ADMINISTRATORS.

PG&E requests the Commission preclude CCA and REN PAs "from issuing third party solicitations for new programs until the IOUs have completed their solicitations by the end of 2022."[1] The Commission should reject this request because it would unreasonably impair and delay CCA and REN solicitations and programs. PG&E's proposal amounts to a misrepresentation of law and fact. As such, the Commission should disregard PG&E's request.

A. PG&E's Proposal Is Contrary to Existing Commission Decisions.

Pursuant to D.16-08-019, CCA and REN business plans are to be considered alongside those of other IOU PAs.[2] Moreover, CCA and REN business plans are to be similarly vetted by the California Energy Efficiency Coordinating Committee ("CAEECC") stakeholders. Nowhere in D.16-08-019 did the Commission direct non-IOU PAs to refrain from conducting solicitations or implementing new programs to accommodate IOU programs. MCE and BayREN are separate and distinct from IOU PAs, and they are not required to wait for the program leftovers from IOUs. It should be incumbent upon any bidder to be aware of the activities of other PAs' programs that overlap with an IOU's service territory when submitting bid proposals; for PG&E, this would include MCE, BayREN, and local government partnerships.

Furthermore, waiting until after the completion of PG&E's solicitation process would likely result in MCE continuing to serve gaps in PG&E's programs, which has historically frustrated MCE's ability to administer a cost effective EE portfolio. PG&E's proposal also fails to

[1] *Opening Comments of Pacific Gas and Electric Company (U 39 M) on the Proposed Decision Addressing Third Party Solicitation Process for Energy Efficiency Programs* (PG&E Opening Comments), filed December 4, 2017, at p. 9.
[2] D.16-08-019, Ordering Paragraphs 1 and 2 at pp. 108-09.

account for, and consequently undermines, MCE's statutory obligation to administer cost effective EE programs.[3]

B. PG&E's Proposal Would Undermine MCE's Efforts to Administer a Cost Effective Energy Efficiency Portfolio.

PG&E requests priority for IOU EE solicitations and contracts for their programs.[4] This would inappropriately disadvantage local, non-IOU PA solicitations and programs (*e.g*. CCAs and RENs) by delaying their solicitations and implementation until the IOUs complete their respective solicitation processes; this could be as late as 2022. To support its request, PG&E cites its statutory obligation to meet Commission-assigned energy efficiency goals.[5] PG&E's attempt to argue that its obligation overrides the activities of non-IOU PAs is misguided. PG&E has had an obligation to maximize energy savings long before the Commission issued D.16-08-019. Moreover, PG&E fails to acknowledge MCE's statutory authority to administer EE programs and its obligation to administer a cost effective EE portfolio.

Were the Commission to adopt PG&E's request, local, non-IOU PAs' solicitations and programs would be relegated to filling gaps in IOU programs, which would (1) undermine MCE's efforts to administer a cost effective EE portfolio; (2) impair CCA and REN PAs' ability to strategically solicit and design their programs; and (3) interfere with CCA and REN PAs' ability to leverage the expertise of local governments to address the needs of their constituents in energy and other program implementation.

[3] *See* Pub. Util. Code Section 381.1 (a)-(d).
[4] PG&E Opening Comments at p. 9.
[5] *Id*. (citing Cal. Pub. Util. Code Section 381.1).

C. PG&E's Request Interferes with CCA and REN PA Solicitation Processes.

PG&E contends its request would support the Commission's finding that "each PA is ultimately responsible for its own solicitation process." This position is contradictory and misleading. PG&E argues that IOUs should not be required to modify their program designs to accommodate CCA and REN portfolios.[6] Yet, the precise effect of adopting PG&E's request would be to interfere with CCA and REN PA responsibility for their respective solicitation processes for new programs by forcing non-IOU PAs to delay their solicitation processes until the IOUs conclude their processes. This would likely require MCE and BayREN to modify their program designs and delay implementation to accommodate the IOUs' portfolios, which is precisely what PG&E objects to on its own behalf. The Commission has not directed MCE or the RENs be precluded from proposing or having business plans approved until after IOUs complete their solicitations. Furthermore, non-IOU PAs were approved in part to leverage the expertise of local governments in addressing the needs of their constituents. This expertise includes the potential for unique and valuable program design for energy and other program implementation.

Contrary to PG&E's assertion, its request would frustrate the Commission's intent to have each PA ultimately responsible for its own solicitation process. As such, the Commission should disregard PG&E's request and instead direct IOU PAs to coordinate with non-IOU PAs with overlapping service territories.

D. The Commission Should Require IOUs to Coordinate with CCAs and RENs During Formation of the Scope of the Solicitation Process and Bid Selection.

PG&E also urges the Commission to deny MCE's request to coordinate with PG&E on the scope of PG&E's solicitations.[7] Ironically, PG&E's comments illustrate the importance of explicit

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[6] *Id*. (citing Proposed Decision at p. 43).
[7] *Id*. at p. 9.

Commission direction to IOUs regarding coordination with CCA and REN PAs throughout the solicitation process. Early coordination among PAs with overlapping service territories will largely obviate PG&E's concerns by helping to: (1) identify areas of program overlap; (2) define solicitations to avoid and account for program overlap; and (3) facilitate a timely and efficient solicitation process that anticipates each PA's strategies and goals prior to program design and implementation. As such, coordination would not interfere with PG&E's strategy for achieving its energy savings goals. Instead, PA coordination would likely reduce the likelihood that PAs would need to revise their strategies once program implementation has commenced.

III. CONCLUSION

MCE and BayREN thank Commissioner Peterman, Administrative Law Judge Fitch, and Administrative Law Judge Kao for their thoughtful consideration of these reply comments.

Respectfully submitted,

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December 11, 2017

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December 29, 2017

Via Regular Mail and E-Mail

Mr. Ed Randolph
Director, Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: CCA Parties' Comments on Draft Resolution E-4909

Dear Mr. Randolph:

Pursuant to Rule 14.5 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the notice accompanying Draft Resolution E-4909 ("Draft Resolution"), East Bay Community Energy ("EBCE"), City of Lancaster, Marin Clean Energy ("MCE"), Peninsula Clean Energy ("PCE"), Silicon Valley Clean Energy ("SVCE") and Sonoma Clean Power Authority ("SCP") (collectively, the "CCA Parties") respectfully offer the following comments on the Draft Resolution.

The CCA Parties acknowledge and applaud the Commission's effort to expeditiously replace fossil fuel-powered generation resources with energy storage and preferred resources in order to address local reliability needs and to obviate the need for reliability must-run ("RMR") resources. As further described below, the CCA Parties have initiated similar efforts, and the CCA Parties welcome the opportunity to collaborate with the Commission and to participate in the Commission's ongoing efforts in this regard. Indeed, the situation presented in the Draft Resolution provides a unique opportunity for the Commission to implement creative options and solutions offered by Community Choice Aggregators.

The CCA Parties do, however, have concerns with the Draft Resolution. The expedited process described in the Draft Resolution runs the risk of exacerbating over-procurement and stranded costs problems, and raises procedural and due process issues. Most importantly for the CCA Parties, the Draft Resolution fails to provide any opportunity for Community Choice Aggregators to self-procure in order to address the identified generation-related problem. In failing to provide or meaningfully consider a self-procurement option for Community Choice Aggregators, the Draft Resolution is not in harmony with statutory provisions that seek to maximize Community Choice Aggregators' opportunity to self-procure.[1]

For these reasons, the Draft Resolution should be withdrawn or rejected without prejudice, and the need for replacement RMR resources should be considered in a full

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[1] *See, e.g.,* Pub. Util. Code § 380(b)(5).

Commission proceeding. In the alternative, if the Commission proceeds with the Draft Resolution, the Draft Resolution should be modified to: 1) provide Community Choice Aggregators a meaningful self-procurement option; and 2) require that Pacific Gas and Electric Company ("PG&E") secure Commission approval of all contracts resulting from the solicitation in a formal Commission proceeding with full review.

BACKGROUND

The Draft Resolution provides the following background information. Calpine has indicated that it wishes to retire four natural gas-fired peaker plants on the grounds that the plants are no longer economic to operate at current energy and Resource Adequacy ("RA") capacity prices.[2] The California Independent System Operator ("CAISO"), however, has designated three of the four facilities as RMR resources.[3] Specifically, CAISO has determined that:

- The 47.6 MW Yuba City Energy Center is needed to meet an 18 MW capacity shortfall in the Pease sub-area of the Sierra local capacity area ("LCA").[4]

- The 47.6 MW Feather River Energy Center is needed to alleviate a high voltage issue in the Bogue sub-area of the Sierra LCA.[5]

- The 580 MW Metcalf Energy Center is needed to prevent a 323 MW capacity shortfall in the South Bay-Moss Landing sub-area of the Bay Area LCA.[6]

The Draft Resolution expresses concern with CAISO's designation of these facilities as RMR resources. It specifically notes that the use of RMR resources has been declining for over a decade, and asserts that the normal regulatory process was not followed leading up to the recent RMR agreements.[7] The Draft Resolution specifies the Commission's concern that assigning RMR contracts without competition can "lead to market distortions and unjust rates for power."[8]

To expeditiously address this problem, the Draft Resolution would direct PG&E to solicit bids for energy storage and preferred resources.[9] The resources must come online with sufficient time to ensure that the RMR contracts for the three Calpine plants will not be renewed for 2019, must be located in the relevant sub-areas, and be of sufficient capacity to obviate the need for the

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[2] Draft Resolution at 2.

[3] Draft Resolution at 2-3.

[4] Draft Resolution at 2.

[5] Draft Resolution at 2.

[6] Draft Resolution at 2-3.

[7] Draft Resolution at 3-4.

[8] Draft Resolution at 4.

[9] Draft Resolution at 6-7, 9 (Ordering Paragraphs 1-2).

RMR contracts.[10] Under the Draft Resolution, PG&E would file Tier 3 advice letters for approval of the contracts resulting from the solicitation.[11] Although the Draft Resolution includes language requiring that procurement "be at a reasonable cost to ratepayers,"[12] the contracts would not be subject to full review under the Commission's application process.

COMMENTS

A. The CCA Parties Appreciate The Commission's Efforts To Replace Fossil RMR Resources With Clean Resources

The CCA Parties appreciate the concern expressed by the Commission on the continued use of gas-fired resources under an RMR construct when energy storage and preferred resources are available. As a general policy, the CCA parties support the move towards energy storage and preferred resources, and believe that the Commission and Community Choice Aggregation ("CCA") programs should actively pursue opportunities to replace gas-fired resources with clean resources. The Commission and CCA programs have shared goals in this regard.

The Oakland Clean Energy Initiative is a good example of a CCA program (EBCE) exploring opportunities to contract for energy and RA from local distributed energy resources while PG&E procures reliability products, in order to enable displacement of an aging gas-fired facility.[13] As another example, SVCE and Monterey Bay Community Power are in negotiations for 278 MWs of solar paired with 85 MWs of energy storage, which would pair energy storage with over 30% of the capacity of the project to mitigate use of gas-fired resources.[14] Other examples of CCA interest and involvement can be provided. In short, CCA programs share the Commission's interest in replacing fossil-fuel RMR resources with energy storage and preferred resources, and CCA programs should be regarded as partners in these efforts.

B. The CCA Parties Are Concerned With The Draft Resolution's Approach

Although the CCA Parties support the Draft Resolution's goal of replacing natural gas-fired RMR resources with energy storage and preferred resources, the specific steps that the Draft Resolution would take to achieve this goal raise several significant concerns.

1. The Draft Resolution's Expedited Approach May Add To Over-Procurement And Stranded Cost Concerns

The Draft Resolution proposes an extremely expedited approach to replacing the RMR resources. The Draft Resolution would require that PG&E procure at least 341 MW[15] of

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[10] Draft Resolution at 9-10 (Ordering Paragraphs 3, 4, and 6).

[11] Draft Resolution at 10 (Ordering Paragraph 7).

[12] Draft Resolution at 9-10 (Ordering Paragraph 5).

[13] *See* News Article. *See also* PG&E Press Release.

[14] *See* SVCE Board Meeting Agenda - November 29, 2017. (See Item 6; Pages 131-133.)

[15] 18 megawatts ("MWs") to meet the capacity shortfall in the Pease sub-area of the Sierra LCA, plus 323 MW to meet the capacity shortfall in the South Bay-Moss Landing sub-area of

preferred resources and energy storage over the span of just a few months in order to eliminate the need to renew the existing plants' RMR contracts for 2019.

This approach has not been shown to be necessary, reasonable, or consistent with state law. While the CCA Parties appreciate the Commission's efforts to replace fossil RMR resources with energy storage and preferred resources, January 1, 2019 should not be a hard and fast date. Although continuing with potentially non-competitive RMR contracts for another year (2019) may raise some "market distortion" risks, these temporary risks are outweighed by the risk of bad procedural and substantive outcomes associated with the Draft Resolution's expedited procurement.

The Draft Resolution's expedited approach would exacerbate concerns about over-procurement of generation products and stranded costs. PG&E is already significantly over-procured, with more resources than needed to meet peak demand and RPS compliance.[16] This trend is likely to continue as more and more customers in PG&E's service territory elect to self-generate, implement energy efficiency measures, and/or take service from CCA programs. Unless PG&E's forecasts more accurately incorporate this evolving landscape, PG&E will continue to procure resources – and costs – that yield little to no benefit. Allowing PG&E to engage in procurement on behalf of load reasonably expected to depart in the near term has caused significant stranded cost problems, and allocating the costs of these resources and ensuring that PG&E takes steps to avoid and mitigate stranded resources have become contentious issues across numerous proceedings at the Commission. Authorizing PG&E to quickly enter into more procurement without carefully considering the impact of such procurement on current and future departing load customers will only further exacerbate these concerns. Moreover, as further described below, authorizing PG&E to conduct "on behalf of" procurement for existing and emerging CCA programs runs contrary to statutory directives and principles.

2. The Draft Resolution's Expedited Approach Raises Significant Process Questions

The Draft Resolution would authorize hundreds of MWs of utility procurement without a full Commission proceeding, and with only a single round of comments from parties on a draft resolution. This approach raises a number of questions regarding the adequacy of the procedure being used and, more fundamentally, the Draft Resolution's compatibility with due process.

Authorizing significant new procurement through a resolution, especially one adopted via only one round of comments and without an underlying process (*e.g.*, workshops, proposals for meeting any identified need, review of contract pricing, etc.), runs contrary to requirements and policies that call for a sufficient showing before the Commission and specified findings by the

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the Bay Area LCA. The 341 MWs total does not include additional resources that may be needed to address voltage issues in the Bogue sub-area of the Sierra LCA.

16 *See, e.g.,* D.17-08-025 at 1. *See also,* D.17-12-007 at 14, 56-57.

Commission.[17] In the Draft Resolution, the Commission has made a finding that new procurement is justified without a showing before the Commission. In addition, the Draft Resolution relies on a number of factual assertions and makes a number of factual findings.[18] These assertions and findings, however, are not supported by any evidentiary record.

The approach described in the Draft Resolution also appears to be at odds with due process, particularly as related to the opportunity for CCA programs to offer self-procurement options and alternatives in lieu of non-bypassable charges on their customers. In Commission proceedings, "there must be due notice and an opportunity to be heard, the procedure must be consistent with the essentials of a fair trial, and the Commission must act upon evidence and not arbitrarily."[19] The proposed procurement raises a number of issues of significant public interest, particularly in regard to the emergence of CCA programs and the involvement of these programs in examining and proposing solutions to generation-related problems. Denying CCA programs an opportunity to be heard on these important issues ignores the significant contributions that are being made and can be made by CCA programs, quashes creativity and collaboration, and is inconsistent with due process.

The process set forth in the Draft Resolution is also inconsistent with the Commission's statutory duty to ensure just and reasonable rates. Under the Draft Resolution, the only Commission review of PG&E's procurement would be the contracts' "approval" through Tier 3 advice letters. Advice Letters are "informal requests" to "review a utility's request to change its tariffs in a manner previously authorized by statute or Commission order."[20] General Order 96-B specifically states that the application process, not the advice letter process, must be used by a utility to "seek approval of a rate increase; a change to its tariffs; or an alteration of any classification, contract, practice or rule so as to result in a new rate."[21]

Equally troubling is the fact that the Draft Resolution does not specify how many MWs of resources PG&E is allowed to procure. The Draft Resolution provides PG&E with a procurement "floor" (PG&E must procure at least enough resources to obviate the need to renew the RMR contracts for 2019) but does not put any clear "ceiling" on PG&E's procurement.

3. The Draft Resolution Does Not Provide Meaningful Consideration Of Alternatives And Mitigating Factors

The Draft Resolution unreasonably focuses on a single solution – the immediate replacement of RMR resources with PG&E-procured energy storage and preferred resources – without considering possible alternatives or the impact that other planned procurement may have on reducing the need for replacement resources. Without a full evidentiary record, it is not

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[17] *See, e.g.,* Pub. Util. Code § 454(a).

[18] *See* Draft Resolution at 8-9 (Findings 1-16).

[19] *See Railroad Commission of California Et. Al. v. Pacific Gas & Electric Co* (1938) 302 U.S. 388, 393.

[20] GO 96-B, Rule 3.1, Rule 5.1.

[21] GO 96-B, Rule 5.2.

possible to determine the viability of alternatives to the RMR resources and PG&E procurement. However, it is clear that possible alternatives exist. Of first note, the LCAs affected by the expected procurement encompass various CCA programs, and it is highly likely that these CCA programs would propose alternatives and options. In addition, Assembly Bill ("AB") 2868 (2016) authorizes PG&E to submit proposals for up to 166.6 MWs of energy storage programs and resources. Directing PG&E to use its AB 2868 procurement process to address the voltage and RA issues in the relevant sub-areas could mitigate the need for additional (duplicative) energy storage procurement.[22] In addition, it does not appear that the Draft Resolution considers the possible RA and voltage impact of planned CCA procurement, which may reduce the need for replacement resources. As further discussed below, CCA programs, which are projected to account for a significant share of customer load in PG&E's service territory, can and should play a key role in replacing the RMR resources.

C. The Draft Resolution Should Be Revised To Allow CCA Programs To Self-Provide Their Respective Share of Resources

If the Commission goes forward with the Draft Resolution, the Draft Resolution should, at a minimum, be revised to allow each CCA program to self-provide its share of the RA need associated with retiring these plants, and to ensure that all self-providing CCAs are exempt from paying non-bypassable charges for PG&E procurement.

The fundamental purpose underlying CCA programs is to allow local communities to choose their own generation resources. This purpose is expressly set forth in statute, where Community Choice Aggregators are solely responsible for all generation procurement activities for their customers, unless expressly stated otherwise in statute, and where the Commission is directed to pursue objectives that maximize the ability of CCA programs to determine the generation resources used to serve their customers.[23]

Directing investor-owned utilities ("IOUs") to procure resources on behalf of CCA customers, with no meaningful opportunity for Community Choice Aggregators to self-procure, is contrary to these statutory principles and directives. Such "on behalf of" procurement binds local communities to paying for resources that they did not voluntarily select, and reduces the amount of a community's portfolio over which it has control. By handcuffing local choice and burdening CCA programs with non-bypassable charges, "on behalf of" procurement undermines CCAs ability to procure resources based on local preferences, undermines the ongoing evolution of energy service away from monopoly IOU control, and reduces communities' incentive to form CCA programs. This is directly contrary to the State's established policy of encouraging CCA formation.[24] Equally important, excluding CCA programs from the procurement process stifles

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22 AB 2868 enacts Pub. Util. Code Section 2838.2(b), which specifically requires that energy storage "programs and investments proposed by the state's three largest electrical corporations shall seek to minimize overall costs and maximize overall benefits."

23 *See, e.g.,* Pub. Util. Code §§ 366.2(a)(5) and 380(a)(4) (added by Senate Bill ("SB") 790) (2011).

24 *See, e.g.,* D.04-12-046 at 3 ("The state Legislature has expressed the state's policy to permit *and promote* CCAs by enacting AB 117…."). *See also* D.10-05-050 at 13 ("Certainly,

creativity and collaboration, which limits alternatives and opportunities for achieving the Commission's goals.

The Draft Resolution should be modified to include a self-procurement option for Community Choice Aggregators. Including a self-procurement option in this circumstance is a reasonable next step in light of the Commission's integrated resource planning ("IRP") process. In the context of the IRP process, SB 350 requires the Commission to permit CCA programs to self-provide their share of renewable energy integration resources, subject to certain findings by the Commission.[25] The IRP process is intended to be an "umbrella" process that covers all of the Commission's various procurement mandates, including RA and energy storage. Energy storage resources are, by definition, renewable integration resources, as they allow the storage of excess renewable generation. This makes it particularly appropriate for the Commission to adopt a self-procurement option for CCA programs in this context.

In this instance, there is no legal, practical, or policy reason why CCA programs should be denied the opportunity to self-procure their share of any identified need for replacement resources. Resources procured by CCA programs provide the same RA benefits as equivalent resources procured by IOUs, and CCA programs are capable of procuring RA resources. As noted above, numerous CCA programs operate within the affected LCAs, and CCA programs have shown a strong interest in exploring and contributing to resource solutions.[26] Community Choice Aggregators currently meet system, local, and flex RA requirements through their own procurement. In addition, allowing CCA programs to self-provide will reduce the potential for disagreement over the allocation of replacement resource costs.

REQUESTED MODIFICATIONS

For the reasons set forth above, the CCA Parties respectfully request that the Commission reject the Draft Resolution without prejudice and instead consider the need for replacement RMR resources in a full Commission proceeding. However, if the Commission proceeds with the Draft Resolution, the Draft Resolution should be modified, at a minimum, to: 1) provide CCA programs with a meaningful self-procurement option; and 2) require that PG&E secure Commission approval of all contracts resulting from the solicitation in a formal Commission proceeding.

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Section 336.2(c)(9) evidences a substantial governmental interest in *encouraging the development* of CCA programs and allowing customer choice to participate in them.").

25 *See* Pub. Util. Code § 454.51(d).

26 *See* notes 13 and 14, above.

CONCLUSION

The CCA Parties thank the Commission for its consideration of these comments.

Respectfully,

/s/

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Service Lists: R.17-09-020
R.15-03-011

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of its Residential Rate Design Window Proposals, including to Implement a Residential Default Time-Of-Use Rate along with a Menu of Residential Rate Options, followed by addition of a Fixed Charge Component to Residential Rates (U 39-E)	Application 17-12-011 (Filed December 20, 2017)

PROTEST OF MARIN CLEAN ENERGY, SONOMA CLEAN POWER, PENINSULA CLEAN ENERGY, AND SILICON VALLEY CLEAN ENERGY

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January 22, 2018

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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PROTEST OF MARIN CLEAN ENERGY,
SONOMA CLEAN POWER, PENINSULA CLEAN ENERGY,
AND SILICON VALLEY CLEAN ENERGY

Pursuant to Rule 2.6 of the Rules of Practice and Procedure of the Public Utilities Commission of the State of California ("Commission"), Marin Clean Energy ("MCE"), Sonoma Clean Power ("SCP"), Peninsula Clean Energy ("PCE"), and Silicon Valley Clean Energy ("SVCE"), which manage and operate Community Choice Aggregation ("CCA") programs (collectively "CCA Parties"), hereby file this protest to Pacific Gas and Electric Company's ("PG&E") Application for Approval of its Residential Rate Design Window Proposals, including to Implement a Residential Default Time-Of-Use Rate along with a Menu of Residential Rate Options, followed by addition of a Fixed Charge Component to Residential Rates ("Rate Design Window Application"). Notice of PG&E's Rate Design Window Application first appeared in the Daily Calendar on December 22, 2017. Therefore, in accordance with Rules 2.6(a) and 1.15, this protest is timely filed.

I. INTRODUCTION

The CCA Parties have been actively engaged with PG&E and the Commission on residential rate matters through both formal and informal avenues in order to prepare for the rollout of residential time-of-use ("TOU") rates, including in CCA program service territories. Since CCA programs are rapidly expanding as a service model across the state, and especially in PG&E's service area, the CCA Parties seek to ensure that CCA programs and CCA customer interests are afforded due and equal consideration in the rollout of residential TOU rates.

The CCA Parties have reviewed the Rate Design Window Application and identified a number of preliminary issues that should be explored in this proceeding. At the outset, the CCA Parties express support for PG&E's proposal to delay default TOU transition until October 2020. The CCA Parties also support PG&E's proposal to simplify its California Alternative Rates for Energy ("CARE") subsidy.

However, the Rate Design Window Application is flawed for a number of reasons, and should not be approved as-is. As explained in more detail below, the chief concern of the CCA Parties in this proceeding is PG&E's continued unwillingness to fulfill its statutory obligation to provide unbundled customers with the same rate comparison and cost-related tools as bundled customers. Moreover, the CCA Parties find PG&E's proposal to recover all default TOU-related costs through distribution rates unfair, unreasonable and contrary to the Commission's cost-allocation principles. Finally, the CCA Parties take issue with PG&E's proposal to roll out all CCA customers in a one-month time period.

While the CCA Parties have identified these preliminary matters and request that these issues receive due consideration, the CCA Parties anticipate propounding discovery requests related to various other matters in PG&E's Rate Design Window Application, and therefore anticipate further review and analysis of these matters. Accordingly, the CCA Parties reserve the right to address and protest other issues in the course of this proceeding as they arise and are further developed. As such, the information presented below is merely intended to inform

PG&E and the Commission of certain preliminary concerns and objections related to the Rate Design Window Application.

II. BACKGROUND

MCE operates California's first CCA program, and currently serves over 250,000 customers in the counties of Marin and Napa, the cities of Richmond, San Pablo, El Cerrito, Benicia, Walnut Creek, and Lafayette. In 2019, MCE will undergo an expansion to serve unincorporated Contra Costa County, the cities of Concord, Martinez, Oakley, Pinole, Pittsburg, and San Ramon, and the towns of Danville and Moraga.

SCP is the second operational CCA program in California and currently serves about 226,000 customer accounts, which includes all of Sonoma and Mendocino Counties, except for the cities of Healdsburg and Ukiah, which have their own municipal utilities. SCP currently provides service to customers in the cities of Cloverdale, Cotati, Petaluma, Rohnert Park, Santa Rosa, Sebastopol, Sonoma, and the Town of Windsor, as well as all of the unincorporated areas in Sonoma County.

PCE commenced service in October 2016 as the fifth CCA program and, as of April 2017, PCE supplies electricity to all of its approximately 300,000 customers. PCE is a Joint Powers Authority formed by the County of San Mateo and each of the twenty incorporated cities therein.

SVCE launched on April 3, 2017, as the sixth operational CCA program in California. SVCE is a Joint Powers Authority consisting of twelve member communities and the County of Santa Clara, and is currently serving approximately 248,000 customers.

III. PROTEST

CCA customers are charged rates under a two-prong construct: (1) for generation services, CCA customers are charged rates set by the CCA program; and (2) for distribution and other services, CCA customers are charged rates applied by the incumbent utility and approved by the Commission. Thus, the CCA Parties' customers receive generation services from the respective CCA program, and receive transmission, distribution, billing and other services from PG&E. This construct, where not all residential rates are set by the Commission, creates the potential for significant confusion in conjunction with the rollout of default TOU rates.

The Rate Design Window Application projects that of the 2.7 million customers eligible for residential TOU default, about 2.1 million customers are expected to take service from a CCA by 2019.[1] Given this recognition that CCA providers are expected to serve a majority of the load in PG&E's service area in the foreseeable future, it is prudent to incorporate input from CCA representatives and the CCA community. The CCA Parties seek to ensure that shared customers are fairly treated and appropriately informed regarding the rollout of residential TOU rates. PG&E and the CCA Parties share the same goal of helping customers seamlessly transition to full default TOU rates as early as 2019. The CCA Parties offer the following comments in furtherance of this goal.

A. The CCA Parties Support PG&E's Proposal To Delay Default TOU Transition Until October 2020

The CCA Parties agree with PG&E's "Option 2" proposal for transition to default TOU rates. The CCA parties agree with PG&E's justifications for the delay, as outlined in its testimony. PG&E rightly acknowledges that it will have to coordinate with at least ten (if not more) CCA programs.[2] PG&E notes "Option 2's schedule allows PG&E to coordinate fully with each individual CCA in its territory, developing details regarding communications, customer tools, and other implementation intricacies."[3] The CCA Parties have consistently advocated for,

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1 *See* PG&E Testimony at 3-10.
2 *See* PG&E Testimony at 3-25.
3 *See* PG&E Testimony at 3-24 – 3-25.

and continue to support, increasing coordination and communication between PG&E and CCA programs. Thus, the CCA Parties support Option 2 for the purpose of ensuring that all CCA programs are engaged and informed prior to the rollout of default TOU rates. Since Option 2 would align TOU roll-out across the two largest investor-owned utilities ("IOUs") in the state, the CCA Parties also agree that "under Option 2, the statewide marketing campaign is more likely to meet its objectives." [4] Finally, the CCA Parties agree that Option 2 will allow full incorporation of the results of PG&E's Default TOU Pilot - a program also involving MCE and SCP. For all of these reasons, the CCA Parties support PG&E beginning its transition of customers in October 2020, at the same time as Southern California Edison Company ("SCE").

B. The CCA Parties Support PG&E's Proposal To Simplify The CARE Subsidy, But Are Concerned by the Minimum Bill Proposal

The CCA Parties also support PG&E's proposal to simplify its CARE subsidy to make it a single line-item percentage discount to the total bill.[5] The CCA Parties agree that this "simplification will improve CARE customers' understanding of their monthly bills and standardize the discounts across rate schedules."[6] Thus, the CCA Parties support adoption of the proposed change to the CARE subsidy. However, the CCA Parties are concerned that PG&E's Minimum Bill proposal in this proceeding will adversely and disproportionately affect CARE customers. The CCA Parties question the need to raise the Minimum Bill to $15, after it was just recently doubled from $5 to $10. The CCA Parties intend to address this issue further through the course of this proceeding.

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4 *See* PG&E Testimony at 3-25.
5 *See* Rate Design Window Application at 13.
6 *See* Rate Design Window Application at 13.

C. The Commission Should Require PG&E To Provide Online Rate And Cost-Related Tools For CCA Customers Using The Generation Rates Of Each CCA Program

Over the course of the last year, the CCA Parties repeatedly requested that PG&E develop a robust bill comparison tool. On December 16, 2016, through Advice Letter ("AL") 4979-E, PG&E filed a proposal for its 2018 Default TOU Pilot. On January 24, 2017, MCE submitted a timely protest to the Default TOU Pilot. On February 24, 2017, PG&E served AL 4979-E-B, which supplemented PG&E's original proposal with its recommended approach for providing rate comparison tools to CCA customers for the Default Pilot. On March 16, 2017, MCE and SCP responded to AL 4979-E-B, and requested PG&E to provide more details about its proposed long-term solution for a rate comparison tool for CCA customers. In its reply, PG&E stated that it would collaborate with MCE and SCP to develop a long-term solution for a rate comparison tool for CCA customers prior to submitting its plans for the full rollout of default TOU rates. To date, this commitment has not been fulfilled – leaving CCA customers without access to the rate comparison tool they helped fund.

Given past communication on this issue and PG&E's commitment, it is inexcusable for PG&E to now recommend as its long-term solution "using the bundled PG&E rates as a proxy for the CCA rates."[7] PG&E states: "This recommendation leverages the solution being utilized by the TOU Default Pilot Program."[8] MCE and SCP agreed to this "solution" (i.e. PG&E's proposal to set up an auxiliary website to leverage existing PG&E rate modeling functionality to support CCA customers during the Default TOU Pilot) only because there was not a better solution available. However, this makeshift approach is not sustainable, nor is it an acceptable long-term solution.

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[7] *See* PG&E Testimony at 5-6.

[8] *See* PG&E Testimony at 5-6.

CCA providers do not have the necessary data, infrastructure, or cost-recovery mechanism to conduct rate modeling. Moreover, rate comparisons can only be provided by the incumbent IOUs, which are the default billing service providers under Assembly Bill ("AB") 117. Specifically, PG&E has the right and obligation under Public Utilities Code section 366.2(c)(9) to "provide all metering, billing, collection and customer services to retail customers that participate in [CCA] programs." Consistent with this directive, the CCA Parties reiterate their prior request, and ask the Commission to direct PG&E to develop a robust bill comparison tool capable of supporting all CCA programs in PG&E's service territory prior to the rollout of full default TOU rates. Failing to do so would effectively exclude an already large – and growing – portion of PG&E's distribution customers from being able to fully and effectively participate in the roll-out of default TOU rates. This result would not only be inequitable to CCA customers, it would jeopardize the ability of TOU rates to affect the behavioral changes sought by the Commission.

CCA boards are tasked with determining the rate structure for CCA programs. While some CCA programs may choose to adopt TOU rates, others may not. PG&E in its testimony appears to assume that CCA rates will continue to be comparable and congruent with PG&E's rates. This is presumptuous and without support. PG&E states: "As long as the CCAs use a similar rate structure to PG&E, there is not enough difference between the PG&E bundled rate and the CCA specific rates to warrant the additional cost, time, and maintenance efforts to model CCA-specific rate plans."[9] The CCA Parties' disagree. PG&E cannot reasonably expect that CCA rates will continue to mirror PG&E's; there will come a time when CCA rates are not comparable to or congruent with PG&E's. Rate information is a key element of electric service,

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9 *See* PG&E Testimony at 5-4.

and it is simply unacceptable for CCA customers to get service that is second-tier to the service bundled customers receive. This is especially true since CCA customers already pay for rate analysis through distribution charges, and since 2.1 million (of the 2.7 million eligible) customers are expected to take service from a CCA provider by 2019. CCA customers already pay for distribution charges that fund the development of these tools, and therefore, CCA customers are entitled to an accurate and precise rate modeling tool that is comparable to what bundled customers have access to.

Disappointingly, PG&E has yet to offer a viable solution on this issue. As an alternative to using bundled PG&E rates as a proxy, "PG&E recommends that each CCA contract with the rate engine provider and be responsible for the accuracy of their own rate modeling."[10] In concept, this would mean that PG&E's portal would need to send usage data to a CCA-owned platform and output it into PG&E's portal. This approach is unprecedented and unnecessarily complex. Moreover, requiring CCA programs to pay for the development of rate modeling tools would result in additional costs for CCA programs, costs that necessarily the CCA would have to recover through their generation rates. This would not be a problem but for the fact that generation services are competitive; CCA providers compete with IOUs in the provision of generation services. This also would impact customers by requiring them to pay twice for the same services—once in their CCA generation rate and once in their IOU distribution rate. Senate Bill ("SB") 790 (2011) includes various provisions that speak about the IOUs' potential to cross-subsidize competitive generation services and that seek to redress this potential.[11]

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10 *See* PG&E Testimony at 5-14.

11 *See, e.g.,* SB 790; § 2(c) ("Electrical corporations have inherent market power derived from, among other things, name recognition among…joint control over regulated operations and competitive generation services…and the potential to cross-subsidize competitive generation

As the default billing service provider, PG&E is statutorily obligated to create a system that is equitably useful and functional for all customers. CCA customers are entitled access to bill comparison tools, however, it is impossible for CCA programs to provide a comparable service without PG&E support. The CCA Parties have repeatedly asked for PG&E to provide a means of transmitting billed usage and cost data (i.e. historic transmission and distribution charges, generation credit and Power Charge Indifference Adjustment charges) to CCA providers so that the respective CCA program could provide customers with data on historical charges, cost, and rate comparisons. To date, PG&E has declined to do so. Thus, the CCA Parties are unable to provide their customers with the same level of information and service as bundled customers currently receive. This matter must finally be addressed in this proceeding.

D. Rate Design Window Costs Should Not Be Allocated Solely to Distribution Charges

In Resolution E-4846, which approved PG&E's Residential TOU Pilot, the Commission determined that the instant application is the proceeding in which parties may address PG&E's proposed cost allocation methodology for costs associated with the default TOU rollout[12] In the testimony supporting the Rate Design Window Application, PG&E "proposes that such costs be recovered in the distribution component of rates consistent with previous [General Rate Case] decisions."[13] The CCA Parties are concerned by this statement, as well PG&E's proposal to

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services."). *See also* SB 790; § 2(h) ("It is therefore necessary to establish a code of conduct, associated rules, and enforcement procedures, applicable to electrical corporations in order to facilitate the consideration, development, and implementation of community choice aggregation programs, to foster fair competition, and to protect against cross-subsidization by ratepayers.").

[12] *See* Resolution E-4846 at 29 ("We agree that cost allocation for the expenses associated with the full rollout of default TOU can be addressed as part of PG&E's January 1, 2018 Rate Design Window application.").

[13] *See* PG&E Testimony at 6-1.

allocate the entirety of default TOU costs to the distribution function, with no costs being allocated to the generation function.

Undeniably, generation-related components of PG&E's TOU rates are exclusively attributable to generation costs. Thus, as to these components it is not fair, nor is it reasonable to allocate default TOU costs to the distribution function. As mentioned above, CCAs compete with IOUs in the provision of generation services. Therefore, anti-competitive cross-subsidization occurs when costs attributable to the generation function are assigned to the distribution function. PG&E's proposal to include all default TOU costs solely in distribution rates would result in inequitable cost-shifting to CCA customers in contravention of SB 790 and other statutory provisions.[14] PG&E's proposal would also violate past Commission decisions that forbid generation-related costs from being allocated to distribution customers.[15] PG&E's proposal also stands at odds with principles of cost-causation, since it is PG&E's bundled customers, not CCA customers, that impose on PG&E the cost of implementing generation-related components of PG&E's TOU rates.[16] This problem is accentuated when CCA customers are shown to derive no benefit from the rates, and realistically have no opportunity to participate in the rates (since, as CCA customers, they do not participate in PG&E's generation rates).[17]

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14 *See, e.g.,* Pub. Util. Code §366.3 ("The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load.")

15 *See, e.g.,* D.97-08-056 at 8 ("Specifically, we will not permit allocations of generation cost to distribution customers. To do so would compromise market efficiency by producing artificially low utility generation rates […] and provide competitive advantages, which would stifle competition to the utilities.").

16 *See, e.g.,* D.99-06-058 at 7 ("Our policy has consistently been that costs should be allocated to those customers who impose them").

17 *See, e.g.,* D.14-12-024 at 48 ("[I]f a program or tariff is only available to bundled customers, that program's costs shall be allocated solely to generation rates.").

The CCA Parties have a strong interest in ensuring that California's policy goal of facilitating CCA growth and viability is fully realized.[18] In order to achieve this goal, it is important for the Commission to resolve the issue of whether attributing all default TOU costs to the distribution function, as PG&E proposes, violates the statutory prohibition on cost-shifting or otherwise disadvantages CCA programs and their customers. This issue is now ripe for review through the course of this Rate Design Window Application.

E. The CCA Parties Oppose PG&E's Proposal To Have Each CCA Program Transition All Of Its Customers In One Wave

PG&E developed a set of principles to inform the final plan for roll out of TOU rates to eligible customers. One of these principles is "Customers Within Each CCA Will Transition in One Wave."[19] In other words, PG&E's plan endeavors to have each CCA program transition all of its customers in one wave, rather than spreading the transition out over multiple waves over multiple months.[20] The CCA Parties' object to this proposal. The CCA Parties are concerned that transitioning all customers of a single CCA program in a single month would overload CCA call centers and impact the level of service and access to information that CCA customers deserve. The CCA Parties would prefer if transition in a single CCA program area took place over three or more months. Rolling out TOU to CCA customers across multiple months would result in a measured transition, which is comparable to PG&E's plan for bundled customers. The CCA Parties raise this issue now, but are willing to work with PG&E and the Commission to develop a solution that is amenable to all stakeholders.

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18 *See* D.04-12-046 at 3 (emphasis added) ("The state Legislature has expressed the state's policy to permit *and promote* CCAs by enacting AB 117…."). *See also* D.10-05-050 at 13 (emphasis added) "Certainly, Section 336.2(c)(9) [the provision in AB 117 that requires cooperation from the utilities] evidences a substantial governmental interest in *encouraging the development* of CCA programs and allowing customer choice to participate in them.").

19 *See* PG&E Testimony at 3-28.

20 *See* PG&E Testimony at 3-28.

IV. PROCEDURAL MATTERS

As requested in Rule 2.6(d), the CCA Parties provide the following responses:

A. Proposed Category

The instant proceeding is appropriately categorized at "ratesetting."

B. Need for Hearing

The CCA Parties believe that evidentiary hearings may be necessary. However, the CCA parties are willing to work with other parties through stipulations in order to minimize, or perhaps eliminate the need for hearings.

C. Issues to Be Considered

The CCA Parties are still evaluating the Rate Design Window Application and issues associated with PG&E's request, and therefore the CCA Parties reserve the right to identify additional issues that should be addressed in this proceeding. The issues described herein are intended to preliminarily inform PG&E and the Commission of certain preliminary issues with which the CCA Parties have concerns.

D. Proposed Schedule

As indicated above, the CCA Parties support the Option 2 schedule, with default TOU rollout beginning in October 2020. Moreover, the CCA Parties support consolidation of the IOUs' default TOU rate applications for reasons of efficiency, timeliness, and uniformity. The CCA Parties believe a consolidated proceeding, as opposed to separate proceedings, will enable a uniform cost-recovery policy in all three IOU service territories.

V. PARTY STATUS

Pursuant to Rule 1.4(a)(2), the CCA Parties hereby request party status in this proceeding individually for MCE, SCP, PCE and SVCE. As described herein, each of these entities has a material interest in the matters being addressed in this proceeding. The CCA Parties designate the following person as the "interested party" in this proceeding:

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Additionally, the CCA Parties requests "information only" status for the following:

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VI. CONCLUSION

For the reasons stated above, the CCA Parties protest the Rate Design Window Application. The CCA Parties thank the Commission for its consideration of the matters set forth in this protest.

January 22, 2018

Respectfully Submitted,

/s/ Laura Fernandez

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