BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	A. 17-01-013 (Filed January 17, 2017)
And Related Matters.	A. 17-01-014 A. 17-01-015 A. 17-01-016 A. 17-01-017 (Consolidated)

RESPONSE OF THE JOINT PARTIES TO THE OFFICE OF RATEPAYER ADVOCATES' APPLICATION FOR REHEARING OF D.18-05-041

July 20, 2018

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I. Introduction

Pursuant to Rules 1.9, 1.10, and 16.1(d) of the California Public Utilities Commission's (Commission or CPUC) Rules of Practice and Procedure, the Natural Resources Defense Council, The California Efficiency and Demand Management Council, The Greenlining Institute, Marin Clean Energy, and The Small Business Utility Advocates (Joint Parties) submit this response on behalf of 27 additional parties and stakeholders[1] to the "Application of the Office of Ratepayer Advocates for Rehearing of Decision 18-05-041," (Application) filed July 5, 2018. Our comments are summarized below:

1. The Joint Parties urge the Commission to deny the rehearing of the cost-effectiveness orders as the final decision was based on a robust record of comments and

[1] The additional signatories include the following nonprofit organizations, local governments, and implementers (also included in Attachment A): 3C-REN, ABAG/BayREN, Association of Monterey Bay Area Governments, City/County Association of Governments of San Mateo County, City and County of San Francisco, City of Fresno, CLEAResult, Community Environmental Council, County of Los Angeles/SoCalREN, County of San Luis Obispo, Ecology Action, Energy Coalition, Fresno Economic Development Corporation, High Sierra Energy Foundation, Local Government Sustainable Energy Coalition, Redwood Coast Energy Authority, Rising Sun, San Bernardino Council of Governments, San Gabriel Valley Council of Governments, San Joaquin Valley Clean Energy Organization, Santa Maria Valley Chamber of Commerce, Sierra Business Council, South Bay Cities Council of Governments, University of California Office of the President, Valley Vision, Ventura County Regional Energy Alliance, and Western Riverside Council of Governments.

appropriately balances the need to protect customers with providing equitable service to all ratepayers.

2. A move back to requiring a forecast TRC of 1.25 will impact customers who need energy efficiency the most and result in undue burden on hard-to-reach, small business, and disadvantaged ratepayers who must continue to fund efficiency programs but in practice will likely have minimal – if any – services available to them.
3. ORA's claims that a Total Resource Cost (TRC) test value below 1.0 will burden ratepayers is inaccurate; there will be no additional burden on ratepayers as long as the portfolio Program Administrator Cost (PAC or PACT) test is above 1.0.
4. ORA's claim that "Cost-effectiveness forecasts substantially exceed reported and evaluated results" and that "nothing in the record shows that the utilities can deliver energy efficiency portfolios that meet or exceed their cost-effectiveness forecasts" is not applicable given the requirement to bid out at minimum 60 percent of the investor-owned utilities (IOU) portfolio by 2022.
5. Rehearing D.18-05-041 will delay bidding and/or increase risk for implementers while skewing bidding opportunities in favor of implementers who focus primarily on large energy-saving programs.

II. Discussion

The Joint Parties agree with the importance of ensuring that customer funds are prudently spent and that programs achieve their intended energy savings. However, returning to a forecast TRC requirement of 1.25 is not necessary to protect customers and will undoubtedly undermine the state's dual objectives of doubling energy efficiency and ensuring energy equity.[2]

We therefore urge the Commission to deny the rehearing of the cost-effectiveness orders as the Commission carefully evaluated this issue through a robust record,[3] this interim decision on cost-effectiveness is needed during a time of unprecedented outsourcing, and the final order appropriately balances protections of customers with the need to provide equitable service to all ratepayers.[4] Further, this application for rehearing highlights the critical importance of addressing the underlying issues with cost-effectiveness, which should be taken up by the

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[2] California State Legislature, Clean Energy and Pollution Reduction Act of 2015, Senate Bill 350 (De Leon, 2015), October 7, 2015, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

[3] More than a dozen comments and reply comments discussed the issue on the record: https://apps.cpuc.ca.gov/apex/f?p=401:57:0::NO.

[4] D.18-05-041, p.135-136.

Commission (or through a stakeholder motion)[5] as soon as possible.

Specifically, the Commission should reject ORA's request for rehearing for the following reasons: (1) The claims that the decision burdens customers are either inaccurate or no longer applicable given recent Commission direction and will result in extensive cuts to programs that are critical to meeting Commission and state goals; (2) The Commission appropriately adjusted direction, on a temporary basis, to maintain customer protections while balancing the need to implement the extensive policy modifications that have been adopted since the 2012 cost-effectiveness decision and to minimize the immediate real-world impacts that a forecast TRC 1.25 would have on customers; and (3) Rehearing D.18-05-041 will delay bidding and/or increase risk for implementers while skewing bidding opportunities in favor of implementers who focus primarily on large energy saving programs.

A. The claims that the decision burdens customers are either inaccurate or no longer applicable given recent Commission direction and will result in extensive cuts to programs that are critical to meeting Commission and state goals.

1. ORA's claims that a TRC value below 1.0 will burden ratepayers is inaccurate given that it is the cost to the utilities that are borne by customers through rates (not the cost to participating customers); further, the Program Administrative Cost test that measures the utility costs against the benefits to customers has historically been above 1.0 on an evaluated basis.

The Joint Parties support striving for ever increasing cost-effective portfolios and agree that the Commission should ensure prudent investments that are "just and reasonable."[6] Counter to ORA's claims, D.18-05-041 does just this. In practice, the funding collected through rates equals the cost to the <u>utilities</u> to implement the efficiency portfolio. The PAC then compares this funding (collected in rates) to the benefits of the portfolio to assess impacts on customers. A value above 1.0 means the program portfolio provided more benefit to customers than cost to the utilities.

As seen in Table 1, the utilities' PAC values that were approved by the Commission are projected to be above 1.0 through 2020 without codes and standards. Therefore, ORA's statement that "approving energy efficiency portfolios based on marginally cost-effective forecasts risks burdening ratepayers" is inaccurate since the PAC values are not marginally

[5] D.18-05-041, p.75.
[6] California Public Utilities Code Section 451.

cost-effective.[7]

Table 1: Average Projected PAC Values Without Codes and Standards[8]

IOU	2018-2020
PG&E	1.27
SCE	1.98
SCG	1.47
SDG&E	1.19

Further, as aptly noted by ORA:

> "The purpose of the energy efficiency portfolio is to produce energy savings, which have economic value. Saving energy allows ratepayers to avoid the costs of constructing and operating generation plants, procuring natural gas, constructing and maintaining transmission and distribution infrastructure, and complying with state policies to mitigate climate change. Avoiding these costs allow utilities to keep rates lower."[9]

It is PAC that estimates the benefit of energy efficiency described in this passage, which is focused on optimizing utility spending to minimize ratepayer costs. Funding for an energy efficiency portfolio that has a PAC of 1.0 or greater will result in providing energy services to customers at a lower cost than if the utility would have to buy alternative energy resources to meet demand. This is further confirmed by the National Action Plan on Energy Efficiency:

> "A positive PACT indicates that energy efficiency programs are lower-cost approaches to meeting load growth than wholesale energy purchases and new generation resources (including delivery and system costs). A positive PACT indicates that the total costs to save energy are less than the costs of the utility delivering the same power. A positive PACT also shows that customer average bills will eventually go down if efficiency is implemented."[10]

In addition, as seen in Table 2, the PAC for each utility has also shown a cost-effective portfolio consistently over the past two CPUC evaluation studies, which span the 2010-2015 program years. Given the fact that the cost to the utilities is the determining factor for rates, and

[7] Office of Ratepayer Advocates (hereinafter ORA), "Application of the Office of Ratepayer Advocates for Rehearing of Decision 18-05-041," July 5, 2018. p.4 (hereinafter "Application").

[8] CAEECC, "Business Plans," https://www.caeecc.org/business-plans-1.

[9] ORA, "Application," p.9.

[10] National Action Plan for Energy Efficiency (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers*. Energy and Environmental Economics, Inc. and Regulatory Assistance Project. <www.epa.gov/eeactionplan>

the PAC (measuring benefits to customers as compared to costs collected in rates) has consistently been above 1.0 on an evaluated basis, there has been no undue ratepayer impact even when the evaluated TRC calculations are below 1.0.[11] This will likely be true moving forward as well, reaffirming that the Commission decision sufficiently protects customers.

Table 2: Average Evaluated PAC Values Without Codes and Standards[12]

IOU	2010-2012	2013-2015
PG&E	1.44	1.38
SCE	1.81	1.27
SCG	2.52	1.42
SDG&E	1.41	1.12

It is important to note that the most influential reason that the TRC continuously falls below the PAC is due to the added cost borne by the participating customer who must contribute funds above the cost of the rebate to accomplish the program. Therefore, the TRC calculation includes the same benefits and costs as the PAC but adds the participating customer contributions in addition to the cost of the utility investment borne by customers through rates. This added cost is only experienced by the participating customer, who makes an independent choice to participate in the program (usually based on additional benefits beyond energy such as improved lighting, better resale, more comfort, less maintenance, etc.), not by the general ratepayer population.

In addition, determining what cost-effectiveness method fulfils the requirement of "just and reasonable" is within the authority of the Commission to decide. Based on the record, the Commission opted for a temporary cost-effectiveness approach that takes into consideration the realities of a changing policy landscape, the harsh impacts that a forecast TRC 1.25 requirement would have on customers across California, and the fact that the PAC values ensure prudent use of customer funds.

Therefore, ORA's claims that "customers will then be forced to bear the cost of programs which the commission cannot reasonably expected to produce net benefits" and that a

[11] ORA, "Application," p.6.

[12] 2010-2012 PAC values from: CPUC, 2010-2012 Energy Efficiency Annual Progress Evaluation Report, March 2015. PAC Benefits and Costs. Appendix D. Table 12. 2013-2015 PAC values from: CPUC, Energy Efficiency Portfolio Report, May 2018. Table D-1.

TRC below 1.0 would "result in rates that are not just and reasonable, in violation [of] PU Code Section 451"[13] are both inaccurate. A TRC below 1.0 would not impact the broader customer base as long as the PAC is above 1.0, which it has been since 2010 on an evaluated basis and is expected to be through 2020.[14]

2. *Returning to a forecast TRC of 1.25 will result in greater burden to the most underserved ratepayers and create inequity within the customer base.*

If the Commission requires a forecast TRC of 1.25, the PAs will undoubtedly have to cut programs as has been discussed on the record as well as at a California Energy Efficiency Coordinating Committee (CAEECC) meeting.[15] While we agree that programs that are underperforming should be scrutinized for continuation, most of the program cuts would be in the areas of market transformation, residential, small commercial, local government, workforce, training, education, and hard-to-reach.[16]

These programs may offer low immediate energy savings and appear as though they are not producing benefits according to the current cost-effectiveness framework. In actuality, they provide either long-term savings or non-energy benefits that are currently not included in the cost-effectiveness calculation. Further, cutting dozens of programs will produce an enormous and potentially indefinite gap in services to customers as the utilities will have to shrink the overall portfolio to meet the cost-effectiveness requirement. Temporary gaps will also occur as the utilities will have to cut programs in the near-term to comply with the Commission's direction. However, most bids are expected to occur in 2019 meaning programs would launch in late 2019 or early 2020 since it takes substantial time to establish contracts and ramp up activities.

While some programs may be due for cancellation, it is also important to note that

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[13] *Ibid.*

[14] CAEECC, "Business Plans," https://www.caeecc.org/business-plans-1.

[15] CAEECC, "Ad Hoc Meeting re Status of Third-Party Solicitation Opportunities," November 28, 2017. https://www.caeecc.org/11-28-17-ad-hoc-re-tp-solic-n-opps and opening/reply comments on the record: https://apps.cpuc.ca.gov/apex/f?p=401:57:0::NO.

[16] PG&E, "Supplemental: PG&E's 2018 Energy Efficiency Annual Budget Advice Letter in Compliance with Decision 15-10-028, Ordering Paragraph 4," November 22, 2017. Attachment 5. SCE, "Supplemental Filing to Advice 3654-E, Southern California Edison Company's 2018 Energy Efficiency Program and Portfolio Annual Budget," November 22, 2017. Table 14; and SDG&E, "Supplemental - San Diego Gas And Electric Company's 2018 Annual Energy Efficiency Program And Portfolio Budget Request," November 22, 2018. p.6-7.

cutting programs to meet the CPUC requirement of a forecast 1.25 TRC does not automatically mean the programs are wasteful or that the costs are far greater than the benefits as ORA notes.[17] This is especially true for programs where there are extensive benefits beyond energy savings (e.g., increased comfort, improved health, additional workforce development opportunities, services to underserved communities that are costly to provide for this often left behind sector, support for small and medium businesses, technical assistance, among others). In addition, the Commission explicitly recognized the importance of benefits beyond energy savings when they ordered the utilities to quantify co-benefits and local economic benefits of local government energy efficiency programs in hard-to-reach and disadvantaged communities.[18] Therefore, the Commission should not accept ORA's narrow view of benefits, especially given that state law and CPUC direction require a broader view of the value of these programs.

Furthermore, if the PAs need to cut extensive programs to reach the forecast 1.25 TRC requirement, it would leave the portfolio focused on:

- Low-hanging fruit instead of deep energy savings;
- Large commercial programs that can yield the savings needed to offset the costs instead of programs that reach small and medium business customers (regardless of a required penetration rate since the decision may be interpreted to prioritize cost-effectiveness compliance over all other metrics);[19]
- Programs for customer classes and demographics that are more likely to participate rather than those in disadvantaged communities or are considered hard-to-reach who would not upgrade their buildings and homes without intervention; and
- Programs that focus mainly on mature technologies since emerging technologies can cost more to introduce and implement.

In practice, by requiring a forecast TRC of 1.25, the Commission would limit the state's ability to advance deep energy saving opportunities, fall short of serving disadvantaged communities, and would not provide for energy equity as directed by Senate Bill 350. It would also create undue burden on those customers who need support the most as they would be required to continue funding the energy efficiency portfolio without having many – or any – programs available to them.

[17] ORA, "Application," p.10.
[18] D.18-05-041, Conclusion of Law 69 at page 180 and Ordering Paragraph 30 at page 188.
[19] D.18-05-041, p.28 and p.133.

3. *ORA's claim that the past predicts the future is no longer an appropriate comparison given recent Commission direction.*

ORA notes that "Cost-effectiveness forecasts substantially exceed reported and evaluated results" and that "nothing in the record shows that the utilities can deliver energy efficiency portfolios that meet or exceed their cost-effectiveness forecasts." This argument is not accurate based on the previous discussion of the evaluated PAC values and does not hold moving forward regarding TRC since the utilities must bid out - at minimum - 60 percent of the investor-owned utilities (IOU) portfolio by 2022. This was something that ORA supported in the hopes to "encourage market discovery, creative program ideas, as well as competitive program costs."[20] Cost-savings was also included as part of the rationale for moving to this framework in the final decision on the matter.[21]

Since the bidding process was intended to yield more cost-effective programs and the utilities are now only in charge of identifying energy saving needs and running solicitations - no longer are they in the role of program design - the position that past TRC accomplishments predict the future is no longer valid.

B. The Commission appropriately adjusted direction, on a temporary basis, to account for the extensive policy modifications since the 2012 cost-effectiveness decision and the real-world impacts that a forecast TRC requirement of 1.25 would have on California customers.

Since 2012 when the Commission directed a required forecast TRC of 1.25, numerous policies that impact the composition of the portfolio have been implemented without any updates to the cost-effectiveness inputs or framework (with the exception of avoided costs). Specifically, many policy changes have led to requiring programs that are very beneficial to customers, but that add substantial cost without yielding comparable energy savings. These changes include (but are not limited to):

1. AB 758 focus on improving the energy efficiency workforce;[22]
2. SB 350 focus on disadvantaged programs;[23]

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[20] ORA, "The Office of Ratepayer Advocates' Response to the Administrative Law Judge's Ruling Regarding Comments on Phase I Workshop 3," p.10.

[21] D.16-08-019, Finding of Fact 19.

[22] CEC. "2016 Existing Buildings Energy Efficiency Plan Update," December, 2016 p.50 http://www.energy.ca.gov/ab758/.

[23] CEC: http://www.cpuc.ca.gov/discom/.

3. SB 350 requirement to pursue Market Transformation efforts;[24] and
4. Commission direction to focus on small and medium business.[25]

The sum of these actions results in a TRC value that is no longer able to be driven by only highly cost-effective resource programs, yet the cost-effectiveness framework continues to focus primarily on avoided energy use. This creates an extensive imbalance between what the Commission and state law directs the PAs to do and how we measure the value and reasonableness of those investments when evaluating cost-effectiveness.

The Commission appropriately balanced the need for prudent use of funding (as described in Section A) with the reality that these new policies require a different portfolio composition than previous iterations. Further, the Commission has plans to address many of the underlying issues with how we value efficiency in R.13-11-005. For those cost-effectiveness matters that are not included, the Commission has allowed for stakeholders to address such issues by a motion.[26] Addressing these issues should be prioritized in the coming year to allow for more accurate assessment of efficiency costs and benefits in compliance with state law.

C. Rehearing D.18-05-041 will delay bidding and/or increase risk for implementers while creating an inequitable opportunity for implementers.

If the Commission were to rehear this particular issue, the overdue and much needed bidding activity would be delayed given that the PAs would need to take time to readjust their approach based on updated direction. In addition, since the utilities will go out to bid to comply with the existing decision, the implementers would experience increased regulatory risk as the future composition of the portfolio would be unknown if this decision is reheard and ultimately modified. It is possible that bidders either in the middle of the solicitation process or with a fully executed contract could find themselves with programs that are no longer suitable and could face cancellation despite extensive investment of time and money.

Since one of the hopes of bidding was to find cost efficiencies, the Commission should maintain its decision to allow for a forecast TRC 1.0 requirement during the transition to third-party bids. Imposing a restrictive TRC early in the bidding process – especially when customers are protected as long as the PAC is 1.0 - will limit the potential for portfolio innovation that

[24] SB 350: https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB350.
[25] D.18-01-004, p.52-53.
[26] D.18-05-041, p.75.

could result in significant cost savings.

Furthermore, such a decision would unduly reduce the number of third-party implementers bidding into markets that are traditionally hard and expensive to serve and/or those with low savings potential, thereby stranding ratepayers in those sectors. Solicitations targeting hard-to-reach and small commercial sectors, disadvantaged communities or whole-building upgrades will likely have low bidder participation, and in the absence of local government intervention (programs that would likely be cancelled to reach the threshold of a forecast TRC 1.25), these customers will likely remain unserved or underserved.

Instead of a diverse cross-section of third-party implementers, the Commission will likely see only those implementers that have the capacity for savings-rich programs that serve already robust sectors such as large commercial and upstream programs. Constricting the TRC threshold will have a direct impact on the composition of bidders - and subsequently the diversity and breadth of programs - thereby yielding an imbalance in market participation, stranded sectors, and a lack of innovation.

III. Conclusion

The Joint Parties appreciate the opportunity to provide this response. We reiterate our recommendation that the Commission not rehear D.18-05-041 and instead allow for the much-needed bidding to occur while addressing the underlying cost-effectiveness issues as soon as possible.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues	Rulemaking 13-11-005 (Filed November 14, 2013)

COMMENTS OF THE NATURAL RESOURCES DEFENSE COUNCIL (NRDC) AND SIERRA CLUB ON THE ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON THE THREE-PRONG TEST

July 17, 2018

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Pursuant to Rules 1.9 and 1.10 of the Commission's Rules of Practice and Procedure, the Natural Resources Defense Council (NRDC) and Sierra Club (together, the "Joint Environmental Parties") respectfully submit these comments on the *Administrative Law Judge's Ruling Seeking Comments on the Three-Prong Test* ("Ruling") issued June 25, 2018. In addition to the two parties submitting these comments, we also represent 18 stakeholder organizations that affirm the importance of updating the Three-Prong Test ("Test") and support these comments:

- Ardenna Energy LLC
- Association for Energy Affordability (AEA)
- Association of Bay Area Governments (ABAG) / San Francisco Bay Area Regional Energy Network (BayREN)
- Carbon Free Palo Alto
- Center for Sustainable Energy (CSE)
- City and County of San Francisco
- City of Arcata
- City of Berkeley
- Clean Coalition
- County of Contra Costa / East Bay Energy Watch
- County of Marin / Marin Energy Watch
- Design AVEnues LLC
- Efficiency First California
- Guttmann & Blaevoet
- Marin Clean Energy (MCE)
- Redwood Energy
- Silicon Valley Clean Energy (SVCE)
- Sonoma Clean Power

The Joint Environmental Parties appreciate the focus in the Ruling on updating the Test itself and considering practical issues regarding implementation.[1] It is important that the Test be aligned with Commission policy and be *actionable*, so that the Commission can ensure outcomes that are in the best interest of utility customers and that support California's energy and climate goals. As the Commission reconsiders the Test, we recommend exploring policy options through the lens of how to encourage and support beneficial fuel substitution that would cut customer bills and reduce greenhouse gas emissions.

I. Background

The core principles described in the three decisions (D.92-02-075, D.92-10-020 and D.92-12-050) on the Test in 1992 are still sound and relevant today. The challenge and opportunity is to update the Test with current information that aligns with those principles and current climate policies, and to make the Test actionable so that the objectives described in the 1992 decisions are realized. Currently the Test is not a usable tool, and so has blocked most fuel substitution opportunities rather than encouraging innovative programs that serve the public interest.

The core issue in 1992 was how to align the interests of the utilities administering energy efficiency programs with the interests of customers, and the public more broadly, when fuel substitution occurred as part of an improvement in energy efficiency. The decisions from 1992 make it clear that environmental concerns were what motivated the creation of the Test. In particular, the Commission sought to develop a test to **avoid increasing the use of nonrenewable resources** and to **avoid environmental harm generally**. Key excerpts from the October 1992 decision make this intent clear:

> "All parties agree that fuel substitution programs should be held to a different evaluation standard than other DSM programs, because of the potential for fuel switching to result in environmental degradation or increased source-fuel consumption." (D.92-10-020, page 6)
>
> "The principle established in D.92-02-075 to promote fuel switching only if it has a neutral or beneficial effect on the environment is sound public policy, and should be upheld." (D.92-10-020, page 7-8)

[1] Ruling, page 2.

> "The goals of this Commission, utilities and customers are also not served by implementing fuel substitution programs that increase source-BTU consumption of nonrenewable resources." (D.92-10-020, page 8)

The Commission also decided in 1992 that fuel substitution programs should have the *same* cost effectiveness test as all efficiency programs (which at the time was a program-level TRC of 1.0); therefore, a "higher bar" of cost effectiveness should not be required for fuel substitution:

> "We reject proposals to require that fuel substitution programs have a TRC ratio at or above 1.20. The additional environmental and source-BTU tests will enable us to make informed decisions as to whether a proposed fuel substitution program should be funded by ratepayers, without adding a higher TRC hurdle." (D.92-10-020, page 8)

In addition, the last decision issued in 1992 on this matter focused on the need to avoid fuel substitution programs that encouraged customers to adopt a second-best fuel substitution measure when an *even better* same-fuel measure was available. As described in 1992, the Commission should ensure that fuel substitution programs are an improvement over "efficient same-fuel equipment available to the customer,"[2] as discussed in more detail in response to Question 1. This principle is critical as it requires fuel substitution programs to be better in terms of saving energy and reducing environmental harm *relative* to the same-fuel options.

The recommendations of the Joint Environmental Parties below are designed to adhere to the following principles drawn from the 1992 decisions: 1) avoiding environmental harm, 2) applying the same bar for cost effectiveness to all energy efficiency programs, and 3) ensuring that fuel substitution programs are an improvement over the available same-fuel technologies.

II. Proposed Test Language

The Joint Environmental Parties offer the following text to replace the current language in the California Energy Efficiency Policy Manual. We also recommend the Commission develop *Guidelines for Fuel Substitution*, which would include the detailed methodologies and sample calculations to run these tests.

[2] D.92-12-050, page 10.

<u>Proposed Test language</u>

Requirements for Energy Efficiency that Involves Fuel Substitution

Energy efficiency that involves fuel substitution may offer resource value and environmental benefits. Fuel substitution programs should reduce the need for supply without degrading environmental quality. Fuel substitution with a primarily load building or load retention character is not eligible for funding. Fuel substitution programs or projects must pass the following tests to be considered for funding:

a. ***Nonrenewable resource consumption:*** *Fuel substitution programs must not increase source-BTU consumption of nonrenewable energy resources compared to the most efficient same-fuel alternative technology currently offered by energy efficiency programs.*

b. ***Environmental impact:*** *Fuel substitution programs must not increase greenhouse gas (GHG) emissions compared to the most efficient same-fuel alternative technology currently offered by energy efficiency programs.*

See the Commission's (forthcoming) ***Guidelines for Fuel Substitution*** *for the methodologies and sample calculations to run these tests.*

If these conditions are met, fuel substitution programs can be funded if they additionally pass the same cost effectiveness standards applied to all energy efficiency measures. The savings baseline used to calculate energy savings for cost effectiveness is the same as for other efficiency measures.

III. Comments on Questions

Question 1. **What ambiguities exist with the current Test definition and/or implementation and what clarifications are needed?**

There are several ambiguities with the Test and clarification is needed, which we describe here and in our response to Question 3.

A. The method to pass the test is ambiguous: The Commission should provide a Test methodology, example calculations, and a list of efficient same-fuel options for fuel substitution measures

The Test does not include a clear methodology or example calculations, which would assist both the Commission and efficiency program implementers in knowing when fuel substitution programs "pass" the Test. Twice in the current text of the Test, the Commission states that the "burden of proof lies with the sponsoring party" to prove an element of the Test, but it is left uncertain what is required to show this burden of proof. Neither the Commission, nor utility customers, are served by this ambiguity. If a fuel substitution program both passes the cost effectiveness screen required of all efficiency programs, and has beneficial energy and environmental impacts, then it should be *encouraged* instead of confounded by a murky standard of proof. The policy rules should be designed to encourage programs that meet the criteria, and should be easy to understand and implement.

The Joint Environmental Parties request that the Commission provide a clearly delineated methodology for passing each element of the Test that it decides to retain, along with example calculations. Additionally, once the "baseline" terminology is clarified, as discussed below, it will also be important for the Commission to provide an initial list of the efficient "same-fuel options" that fuel substitution measures should be compared to in order to ensure relative environmental benefits and energy savings.

B. How to apply a "baseline comparison" is confusing: The Commission should clarify this language to align with the Commission's original intent and with current policy

The "baseline comparison" guidance in the introductory text of the Test is ambiguous – it is unclear what a "baseline comparison" is and how it should be applied to the Test. The current text is the following:

> *For purposes of applying these tests, fuel substitution proponents must compare the technologies offered by their program/measure/project with the industry standard practice same-fuel substitute technologies available to prospective participants that would have TRC and PAC benefit-cost ratio of 1.0 or greater. The burden of proof falls on the party sponsoring the analysis to show that the baseline comparison adheres to this requirement.*[3]

As noted by TURN in their March 15, 2017 response[4] to a previous motion regarding the Test, there have been changes in previous versions of the Test absent Commission decision or ruling. For example, the California Energy Efficiency Policy Manual (EEPM), Version 5, requires a comparison to "the industry standard practice same-fuel substitute technologies available to prospective participants." Whereas the version of this language originally included in D.92-12-

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[3] CPUC (California Public Utilities Commission). 2013. *Energy Efficiency Policy Manual*, R.09-11-014, Version 5, July 5, 2013, pages 24-25: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/EEPolicyManualV5forPDF.pdf

[4] *Response of The Utility Reform Network to the Motion of the Natural Resources Defense Council, Sierra Club, the Solar Industry Association, and the California Energy Efficiency Industry Council Seeking Review and Modification of the Three-Prong Fuel Substitution Test*, filed March 15, 2017 in the IDER (R.14-10-003) proceeding, pages 3-5.

050, affirmed in D.05-04-051, and contained in the EEPM Versions 3, 3.1, and 4, instead points to "the most efficient same-fuel substitute technologies available to the prospective participants."

Here we (1) discuss the original intent of the December 1992 decision and how this intent may be achieved, and (2) propose how to set a baseline for calculating savings based on the rules for all energy efficiency programs.

1) **The Commission's original intent was to avoid fuel substitution programs that encouraged customers to adopt a "second-best" fuel substitution measure when an *even better* same-fuel measure was available**

In recent years, the term "baseline" is most commonly thought of as the basis from which to calculate energy savings. However, the use of this term in the December 1992 decision was to identify the "most efficient same-fuel substitute technologies available" from which to compare the fuel substitution measure. By applying this "baseline" in the Test the Commission would avoid allowing fuel substitution programs that encouraged customers to adopt a "second-best" fuel substitution measure when an *even better* same-fuel measure was available. These excerpts from the decision describe the discussion at the time:

> "The utilities recommend that minimum-standards equipment be used as the baseline for making comparisons among fuel options. NRDC, on the other hand, recommends that the baseline reference be the most efficient same-fuel substitute technology that is currently cost-effective under the TRC test." (D.92-12-050, page 8)
>
> "The comments reflect a fundamental difference in perspective regarding the purpose of ratepayer funding for fuel substitution programs. SoCal and others believe that the purpose should be to improve upon the efficiencies of same-fuel equipment that customers are most likely to install (e.g., minimum standards where those standards exist). NRDC believes that the purpose should be to improve upon the most efficient same-fuel equipment." (D.92-12-050, page 9)

The Commission agrees that fuel substitution programs should improve upon the most efficient same-fuel substitute technologies available:

> "Ratepayers should fund fuel switching only to the extent that fuel-substitution technologies increase net total resource benefits relative to the most efficient, available, same-fuel technologies. To do otherwise would encourage fuel competition in ways that could undermine our resource procurement goals." (D.92-12-050, page 9)
>
> "For example, under SoCal's proposal, customers with electric appliances would be presented with gas-technology options that are more cost-effective than the status quo (or their standard purchase choice). However, this does not necessarily represent a net resource benefit to all ratepayers who fund these programs. If SCE can make available

> efficient electric technologies (for either post-failure or early replacement retrofits) that yield greater net resource benefits then ratepayers are better off encouraging same fuel replacement, rather than fuel switching." (D.92-12-050, page 9)
>
> "Our rules should foster an environment where utilities and vendors are encouraged to compete for ratepayer funds in a manner that is in the ratepayers' best interest. By establishing the baseline as NRDC proposes, vendors of fuel-substitution technologies are encouraged to compete against the proper standard, i.e., **the most efficient same-fuel equipment available to the customer via the utilities' traditional energy efficiency programs**. (D.92-12-050, page 10) (bold added)

The Joint Environmental Parties agree that fuel substitution programs should indeed be an improvement over "efficient same-fuel equipment available to the customer." For example, if the original fuel technology is an electric resistance heater, the substitution of an efficient gas heater must be compared to the efficient electric option. And if the original fuel technology is an inefficient gas heater, the substitution of an efficient electric heater must be compared to the efficient gas option. However, this comparison to the efficient same-fuel technology should be used to ensure greater energy and GHG benefits; the efficient same-fuel technology should **<u>not</u>** be used as a baseline for calculating savings that are used in a cost effectiveness test.

2) The savings baseline for fuel substitution programs should be the same as for all energy efficiency programs when applying the standard cost effectiveness screens

The comparison described in the previous section is based on a binary metric: is the fuel substitution measure *better than* the alternative efficient same-fuel option (i.e., yes or no). On top of this binary metric, fuel substitution programs must also pass the standard efficiency cost effectiveness screens, which is intended to address the question of value to utility customers (i.e. is the program a worthy investment of utility customer funds?).

The "baseline comparison" discussed in the previous section is different than the "baseline" needed to calculate total savings (both in energy and in GHGs) from a fuel substitution program when running a cost effectiveness test. For clarification in our comments, the latter – or energy use at which savings start being counted – is the "savings baseline" (the blue bar A below).

We demonstrate our point in the graphics below. Case 1 is an example of a fuel substitution program where the GHG and energy savings are greater than the efficient same-fuel option (C > B). Case 2 is an example of a fuel substitution program where the GHG and energy savings are less than the efficient same-fuel option (C < B). Case 2 should not pass the Test.

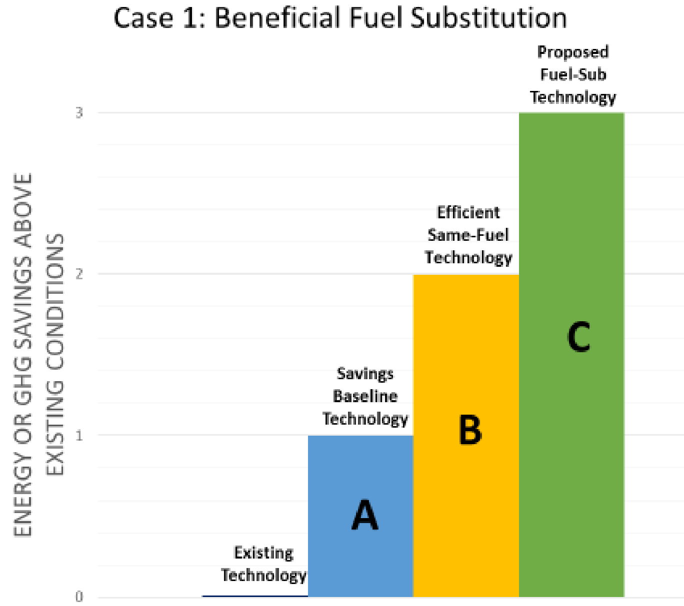

Figure 1: Visual Representation of Beneficial Fuel Substitution

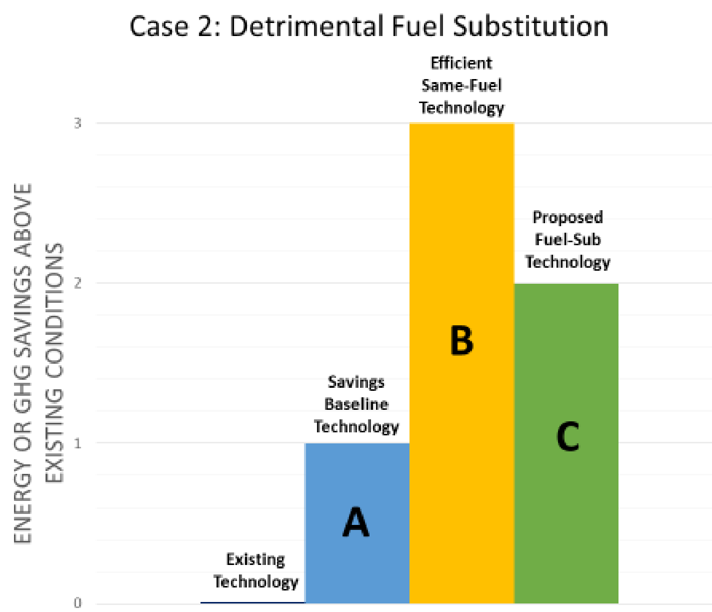

Figure 2: Visual Representation of Detrimental Fuel Substitution

Once this initial comparison is made, programs will also need to apply the standard efficiency cost effectiveness test. Currently this standard is the “duel test” (TRC and PAC) applied at the portfolio level. To run these tests, the savings baseline must be identified to calculate the energy savings or GHG savings used in the cost test. In the graphic, this calculation would be the following:

Savings from the efficient same-fuel technology = **B – A**

Savings from the fuel substitution technology = **C – A**

The value of C – A calculates the full value of the fuel substitution technology from the savings baseline. Importantly, the savings used in a TRC or PAC should **not** be C – B (the savings of the fuel substitution measure *above* the efficient same-fuel option); this would undervalue C relative to the saving baseline. Measuring savings from an artificially high baseline (C – B) undervalues the energy, distribution capacity, and greenhouse gas emission costs avoided by that measure. Because the volume of savings available for each measure directly affects how much a program implementer is able to pay for those savings, using an artificially high baseline also limits the effectiveness of customer rebates. This will also limit the number of customers that can take advantage of beneficial fuel substitution programs.

Instead, the savings baseline for fuel substitution programs should be the same as for all energy efficiency programs. Baseline policy has evolved over time, and may continue to evolve. It should evolve for all efficiency programs uniformly. Currently, per the energy efficiency policy manual, baseline is "the state of performance and/or equipment that would have happened in the absence of the program-induced energy efficiency."[5] In other words, the savings baseline should represent customer choice in absence of the program, not optimal behavior or policy goals. Therefore, the Joint Environmental Parties recommend that the current default savings baseline for fuel substitution be the minimum code or standards requirements for existing 'original fuel' technologies.[6] The language in the Test can simply point to the savings baseline used for all programs, rather than suggest a special practice for fuel substitution programs. As expressed in the October 1992 decision, "The additional environmental and source-BTU tests will enable us to make informed decisions as to whether a proposed fuel substitution program should be funded by ratepayers, without adding a higher TRC hurdle."[7] This is a key clarification needed for counting the full value of the savings achieved, while using the efficient same-fuel

[5] CPUC Energy Efficiency Policy Manual, Version 5, July 2013, pg. 47.
[6] This recommendation is discussed further in our answer to Question 3b.
[7] D.92-10-020, page 8.

technology "comparison" in the Test to avoid suboptimal fuel substitution measures that foreclose on better same-fuel options, if available.

C. There is ambiguity related to fuel switching that should be addressed

An additional ambiguity with the implementation of the fuel substitution test is that it is not applicable to fuel *switching*, the Commission's term for programs that move customers off of an unregulated fuel, such as wood or propane, onto a regulated fuel like electricity or gas.

The inaccessibility of efficiency funds and rebates for fuel switching prevents some of California's most vulnerable communities from transitioning off sources of energy that are expensive and, in the case of wood and propane, cause impaired air quality and harm community health and safety. Many of these customers relying on unregulated fuels for heating or cooking are electric customers who fund efficiency programs through their electricity bills, yet they do not have access to the same rebates and services as other electric customers.

The Commission has previously stated its intent to address the problem of energy efficiency programs that could help to transition customers off of unregulated fuels. When the Test was created in 1992, the Commission agreed that the Test should be broadened to include all fuels, including unregulated fuels.[8] However, the Commission declined to include unregulated fuels in 1992 citing "analytical constraints" that made the evaluation of proposed programs difficult.[9] While the decision does not explain specifically what missing data or other analytical problems parties raised, the existing energy efficiency cost tests are not appropriate for fuel switching programs because the savings of unregulated fuels will not be counted as avoided costs. Further modification of the Test that extends beyond the scope of the current discussion may be necessary to enable utilities to propose fuel switching programs.

In order to capture the energy efficiency savings and greenhouse gas reductions possible by helping customers transition off of unregulated fuels, utilities need guidance on what conditions need to be met in order to use efficiency funds for fuel switching programs. The Joint Environmental Parties propose a short-duration working group that would meet for 3 to 6 months to discuss and propose options for a policy framework to guide fuel switching. A proposal (or

[8] D. 92-10-020, 45 CPUC 2d 683, p. 3.
[9] *Id.* The decision does not specify what missing data or "analytical constraints" parties raised during the proceeding.

proposals) could then be submitted to the Commission for party comments, and ultimately a decision.

***Question 2.* What are the barriers, if any, for energy efficiency program administrators pursuing fuel substitution programs or projects, as they relate to the Test?**

In addition to the lack of clarity as to how to perform the Test, discussed in Question 1, one of the biggest barriers to fuel substitution is the measure-level cost effectiveness requirement in the current Test. For years this has meant that promising fuel substitution measures have not benefitted from program support to drive down initial costs, while same-fuel measures have enjoyed program support despite declining savings potential.

Like any well-diversified investment strategy, energy efficiency program portfolios use very cost-effective measures to balance out deeper savings and more innovative technologies that may not be cost effective yet due to their early stage of market development. Risk and cost-effectiveness are balanced in a way that protects long-term customer interests and allows investment in less certain, more innovative solutions. New technologies are often added to utility programs before they are fully cost effective so that customers can begin purchasing them with the support of financial incentives. This results in accelerated technology adoption and eventually leads to decreases in technology costs and increased cost effectiveness for the newer technologies. This is how newer technology is deployed and markets are transformed.

Yet, fuel substitution measures have not received this initial program support to help get them to measure-level cost effectiveness. This is especially problematic now that many commercially available same-fuel measures would also not meet a TRC of 1.0. In the 25 years since the 1992 decision, California has picked a lot of energy efficiency's "low hanging fruit" and is now facing diminishing cost effectiveness across the board. Since programs have focused on lighter-touch opportunities in the most easily reached markets, much of the same-fuel savings potential that remains involves more costly upgrades to existing buildings. In the meantime, some technology that could lead to fuel substitution, such as electric heat pump technology, has improved considerably. This means that many fuel substitution measures now offer more savings *and* GHG reductions than comparable same-fuel measures.

For example, electric heat pump water heaters can be almost six times more efficient than the minimum efficiency gas water heaters that are mandated by federal standards. In comparison, the most efficient commercially available gas technology is only one and a half times more efficient than the code requirement. Replacing a 50 gallon code minimum gas water heater with the most efficient same-fuel technology saves roughly 5 million BTUs per year; at roughly the same TRC levels, the same code minimum gas heater can be replaced with a heat pump water heater, saving at least 13 million BTUs per year.[10] In other words, the fuel substitution option can deliver twice the domestic water heating savings as a same-fuel measure that is allowed by Commission policy – all at the same level of measure-level cost effectiveness.

The following table compares savings from gas-only domestic water heating measures to savings that could be delivered by fuel substitution water heating measures.

Retrofit Savings Potential for a 50 Gallon, Gas-Fired Domestic Water Heater	
Gas-to-Electric Measure	Annual Site BTU Savings
Existing Conditions Early Retirement (ER) to HPWH, 3.5 EF	15,006,396
Existing Conditions ER to HPWH, 3.24 EF	14,668,608
Code Minimum Replace on Burnout (ROB) to HPWH, 3.5 EF	13,606,396
Code Minimum ROB to HPWH, 3.24 EF	13,268,608
ENERGY STAR, .68 EF to HPWH, 3.5 EF	11,206,396
ENERGY STAR, .68 EF to HPWH, 3.24 EF	10,868,608
Tankless, EF .92 EF to HPWH, 3.5 EF	8,506,396
Tankless, EF .92 EF to HPWH, 3.24 EF	8,168,608
Gas-to-Gas Measure	Annual Site BTU Savings
Existing Conditions ER to Tankless, EF .92	6,800,000
Code Minimum ROB to Tankless, .92 EF	5,100,000
Existing Conditions ER to ENERGY STAR, .68 EF	3,800,000
ENERGY STAR, .68 EF to Tankless, .92 EF	2,700,000
Code Minimum ROB to ENERGY STAR, .68 EF	2,400,000

Table 1: Energy Savings from a Gas-Fired Water Heater Baseline

Switching from gas to electric heat pump water heating delivers significantly more savings than comparable same-fuel measures. The Joint Environmental Parties ran the TRC and PAC tests for a range of measures and found that this leads to heat pump water heater savings

[10] Per CPUC practice, all water heating savings calculations in this document use DEER unit energy consumption values from the "Updated DEER DHW Calculator Workbook" at http://www.deeresources.com/index.php/23-deer-versions. It should be noted that DEER values can be conservative. For example, the projected savings value for the gas to electric measure in this example increases to 20,000,000 BTUs and cost effectiveness doubles if unit energy consumption values from the Northwest Regional Technical Forum are used for the calculations.

that are, on average, more cost effective than the majority of available gas-to-gas domestic water heating measures.[11] This demonstrates one example of why a measure-level cost effectiveness metric for fuel substitution does not make sense – in many cases utility customers will miss out on encouraging the options with the most energy and GHG savings, even at the same or better level of cost effectivenes.

The Joint Environmental Parties urge the Commission to rethink the framework for approving efficiency programs more broadly – we need a clearer focus on GHG savings, a more coherent way of supporting market transformation, and cost tests that better represent value to all customers. We acknowledge that this may be outside the scope of this Ruling. For the topics covered here, we recommend that the Commission focus on ensuring that a proposed fuel substitution measure is a better option than the efficient same-fuel option, as discussed in Question 1, and otherwise apply the same cost effectiveness requirements to all efficiency measures and programs. Currently, this would mean applying a portfolio-level cost effectiveness requirement.

We note that because there is almost no cost effectiveness "wiggle room" in the current portfolio, this will have marginal impact at best on the approval of new fuel substitution programs. However, this is the most coherent way to structure the rules for fuel substitution, and will allow fuel substitution programs to be judged on an equal footing with other programs once they have been shown to have greater saving potential than the same-fuel options. As the parameters for efficiency program funding evolve, we anticipate there will be more opportunities for beneficial fuel substitution. In the meantime, the Commission should also consider proactively encouraging beneficial fuel substitution with targeted market transformation and emerging technology programs, so that these opportunities do not continue to be ignored.

[11] A final report describing this analysis will be available in August 2018. The cost effectiveness analyses reference here and in the rest of this section use incremental cost values averaged from various sources, including links from DEER update workbooks, the MICS database, and other web searches. They assume installation cost that include new electrical circuits but no panel upgrades.

Question 3. **How should the Test be modified, if at all, to provide greater clarity and consistency when measuring fuel substitution programs, projects, or measures?**

The Joint Environmental Parties provide proposed alternative language for the Test in Section II above that reflects the recommendations throughout our comments. Here we provide specific answers to Question 3.

None of the questions in the Ruling address the "cost effectiveness" prong (prong two), which is one of the most significant Test-related barriers to fuel substitution. As we explain above in our response to Question 2, the Joint Environmental Parties recommend that the test be edited to add language noting that fuel substitution measures should pass the same cost-effectiveness test as all energy efficiency resources, and that "prong 2," the requirement of a separate cost-effectiveness test, be eliminated. In this way, changes made to cost effectiveness screening for other efficiency programs would also apply to programs that include fuel substitution.

a. If applicable, how should "source BTU consumption" be defined and measured?

The Joint Environmental Parties recommend that the Commission 1) update the heat rates used for prong one, and 2) require that fuel substitution measures reduce the use of nonrenewable energy compared to the efficient same-fuel measure available. The first recommendation is a necessary update to the Test to reflect the state's projected renewable electricity mix over the life of the measure. The second prevents expenditure of customer dollars on suboptimal fuel substitution when more impactful same-fuel measures are available. It is important to recall that the Commission's concern about the increased use of "depletable"[12] fuels motivated the development of the test: "The goals of this Commission, utilities and customers are also not served by implementing fuel substitution programs that increase source-BTU consumption of ***nonrenewable*** resources"[13] (emphasis added).

i. What value should be used for heat rate?

Heat rates in general, regardless of what data is used to calculate them, are only accurate measures of source-fuel efficiency for electricity that is generated from fossil fuel combustion processes. A heat rate measures the fuel conversion efficiency of thermal electric generators – it is a ratio of the heat input (in carbon-based fuel consumed) to the heat output (in electricity) of a

[12] D.92-10-020, Finding of Fact 6, page 14.
[13] D.92-10-020, page 8.

combustion plant. It does not account for non-fossil based resources, i.e. renewable resources. Therefore, the average heat rate that is calculated from empirical data by the California Energy Commission (CEC) each year is only an accurate measure of the thermal efficiency of California's combustion generation fleet.

However, that 100 percent nonrenewable fuel heat rate is neither a comprehensive nor accurate metric for the performance of California's portfolio of electricity supply resources over the life of the measures; due to significant penetration of renewable resources, the 100 percent nonrenewable fuel heat rate no longer captures the fuel consumption of the whole electricity grid. The 100 percent nonrenewable fuel heat rate now only captures the fuel conversion efficiency of less than 70 percent of California's generation (per the RPS), and this proportion will continue to decrease as the RPS mandate progresses. In fact, counting all non-combustion resources (including nuclear and large hydro), only 55 percent of the electricity consumed in California in 2016 was generated by combustion resources.[14] Because the CEC heat rate only shows combustion generator efficiency, it is only a measure of the fuel consumed for that 55 percent of California's electricity today and less going forward as California continues to progress toward its 50 percent renewables portfolio standard goal. The average heat rate established by the CEC also does not capture the hourly and seasonal variations in source BTU consumption of the electric generation fleet.

Instead, the Commission should use the hourly marginal heat rates that already exist in the ACM. These hourly marginal heat rates already account for the RPS and zero-carbon resources on the grid, avoiding the need to apply a discount factor for zero-carbon resources. This is the most accurate heat rate to understand the use of nonrenewable fuels over the lifetime of energy efficiency measures that involve fuel substitution.

Should the Commission still decide to use the CEC conventional heat rate, it is important that it only applies it only to the portion of power that is generated by fossil fuels, to more accurately measure the rate at which California's entire electricity grid consumes "depletable resources"[15]. The zero-carbon portion of the state's power would need to be accounted for with

[14] CEC, California Energy Almanac, http://www.energy.ca.gov/almanac/electricity_data/total_system_power.html.
[15] D.92-10-020, Finding of Fact 6, page 14.

a different metric: a fuel conversion rate chosen specifically to measure the source fuel efficiency of the remaining 45% of the state's electricity.

The renewable heat rate, or source-fuel conversion factor, could be set as low as 0 and still accurately respond to the Commission's 1992 concern about "consumption of nonrenewable resources."[16] A zero BTU/kWh heat rate accurately represents the zero volume of depletable fuels consumed in renewable generation. Another option is to use the Department of Energy's "captured energy" heat rate for renewable resources. The captured energy methodology for measuring the conversion efficiency of renewable resources assumes that the source energy used for renewable generation is equal to the total electricity output before transmission and distribution. It results in a 3,412 BTU/kWh "renewable heat rate,"[17] which is the BTU equivalent of each kWh generated from renewable sources. The "captured energy" method values energy efficiency whether the energy source is fossil or not, whereas are the carbon content method only values energy efficiency for energy generated from fossil sources.

i. Should an average heat rate, as determined by the California Energy Commission, be used, and if so which specific heat rate should be used?

Please see answer to the previous question.

ii. Instead of an average heat rate, should an average marginal heat rate for each measure's load shape be determined?

Please see answer to the previous question.

iii. Or should the test use an hourly heat rate based on 8760-hour data from the California Independent System Operator (CAISO)?

Establishing new marginal heat rates would be a costly and time-consuming exercise. The Joint Environmental Parties recommend that the existing ACM hourly marginal heat rates be used instead.

iv. Please provide a suggested methodology for your preferred proposal.

The Joint Environmental Parties recommend that the Commission use the following methodology to blend the combustion and renewable heat rates:

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[16] D.92-10-020, page 8.
[17] Paul Donohoo-Vallett, U.S. Department of Energy, *Accounting Methodology for Source Energy of Non-Combustible Renewable Electricity Generation*, October 2016.

$$\mathbf{kWh_{Measure} * HR^{ACM} < BTU_{Baseline}}$$

or

$$\mathbf{BTU_{Measure} < kWh_{Baseline} * HR^{ACM}}$$

where:
$kWh_{Measure}$ = Measure UEC in kWh
$BTU_{Baseline}$ = Baseline UEC in BTU
HR^{ACM} = ACM Hourly Marginal Heat Rate

This calculation would be done for each hour in the measure's life, the same granularity at which avoided costs are calculated.

v. How often should these values be updated?

Values should be updated yearly using the existing rolling portfolio schedule.

vi. How should renewables be accounted for?

As discussed in Question 3(a)(i.i.), the Commission will need to decide on a "renewable heat rate" to use for the percentage of renewable energy in the state's electricity mix. Once that heat rate is created, it should be scaled over time for actual renewable penetration using the RPS milestones and, if possible, the content of distributed renewable generation not included in the RPS. The RPS is a useful accounting tool for renewable penetration because it predicts the generation mix into the future. In addition, there is renewable generation on the grid that is not included in the RPS and this should be included as well.

b. How should the "baseline" be defined against which a proposed fuel substitution project is compared?

This issue was discussed above in Question 1. There are two comparisons that need to be done: 1) the **savings baseline** used to calculate the energy savings applied in a cost effectiveness test, and 2) a **comparison to the efficient same-fuel alternative** to ensure that the fuel substitution measure reduces energy and GHGs beyond this alternative, discussed in Question 1 and in Question 3(b)(i) below.

As discussed in Question 1, the savings baseline should be same baseline used for other efficiency programs or projects. Currently, per the Energy Efficiency Policy Manual, the savings baseline is "the state of performance and/or equipment that would have happened in the absence of the program-induced energy efficiency."[18] In other words, the savings baseline should represent customer choice in absence of the program, not optimal behavior or policy goals. Therefore, the Joint Environmental Parties recommend that the current default savings baseline for fuel substitution be the minimum code or standards requirements for existing "original fuel" technologies.[19] In this section the term "code" is used to refer to the applicable minimum efficiency requirement for the existing technology set by California's Title 20, Title 24, or federal appliance standards.

At this very early point in the adoption curve for fuel substitution measures in California, a code baseline – of the original fuel – would convey the clarity necessary for new program development without unnecessarily distorting savings estimates. A default code baseline makes further sense for fuel substitution programs because of the costs currently associated with the most promising substitution measures. Because fuel substitution measures are in an early stage of market development and also can involve significant retrofit costs, customers are likely to defer any upgrades until the appliance they already own reaches the end of its useful life. At that point, every commercially available appliance will at the very least meet code minimum requirements. In the absence of a fuel substitution program, the customer would then purchase one of those commercially available appliances – one powered by the same fuel that had been used previously for the end use. Therefore, these "original fuel," code minimum appliances are the correct baseline for fuel substitution measures when calculating savings.

The Joint Environmental Parties also recommend that an existing conditions baseline *option* be available to program administrators that are interested in establishing the case for existing conditions. It is likely that most fuel substitution activities will use a code baseline due to ease of application. However, it is important to also allow flexibility to demonstrate deeper energy savings through use of existing conditions if the project would otherwise be eligible for an existing conditions baseline under Commission rules.

i. In setting the baseline for a same-fuel alternative, should the baseline always be code if a code or minimum efficiency standard exists? Or should industry standard practice be used if higher than code?

[18] CPUC Energy Efficiency Policy Manual, Version 5, July 2013, pg. 47.
[19] This recommendation is discussed further in our answer to Question 3b.

In responding to this question, the Joint Environmental Parties assume that this question refers to the second comparison required by the Test – the comparison to the efficient same-fuel alternative to ensure that the fuel substitution measure reduces energy and GHGs beyond this alternative. The distinction between this and the previous answer was described in our response to Question 1. In short, we understand the Commission's original intent to be avoiding fuel substitution programs that encouraged customers to adopt a "second-best" fuel substitution measure when an *even better* same-fuel measure is available. Fuel substitution programs should indeed be an improvement over the "efficient same-fuel equipment available to the customer"[20] in terms of energy and GHG savings. However, more consideration needs to be given to describe this "efficient same-fuel alternative." The current Test language says, "industry standard practice," but that can be difficult to define and also does not meet the spirit of the 1992 decision. The language adopted in 1992 was "the most efficient same-fuel substitute technologies available to the prospective participants that would have a TRC benefit-cost ratio of 1.0 or greater."[21] The spirit of this is correct – the Commission sought to avoid encouraging sub-optimal fuel substitution when better same-fuel options existed and were offered by same-fuel efficiency programs. But there is too much ambiguity with this language, for example:

- What does "available" mean? The *most* efficient technology might be extremely expensive and barely in the market, so it may not be a real alternative, though it might be technically "available."
- What if better same-fuel options exist, even those that are currently being offered in efficiency programs, but they don't currently have a TRC of 1.0 or greater?

We support a comparison to the most efficient same-fuel substitute technology currently offered by the regular energy efficiency program portfolio, regardless of the cost effectiveness of this technology. Our initial assessment is that most fuel substitution opportunities will be addressed by this language, and exceptions can be made for special cases (where an efficient same-fuel option doesn't exist, or is not offered by efficiency programs). Getting this language right and providing enough guidance is a key part of developing a workable Test, and we urge the Commission to further consider the options in a public workshop. In addition to developing this language, the Commission should provide a list of the

[20] D.92-12-050, page 13.
[21] D.92-12-050, page 13.

efficient same-fuel substitute technologies that should be used to compare to specific fuel substitution measures, so that it is clear how to do this calculation.

ii. Given that Title 24 now allows all-electric new homes to meet compliance requirements, should the three-prong test continue to apply to new homes?

In most cases, the Test should only apply to measures installed in existing buildings. Starting in 2020, Title 24 will allow new construction buildings to use all-electric or mixed fuel baselines regardless of the availability of gas to the new building.[22] The all-electric Title 24 option now offers high-efficiency electric baseline technologies for all residential and small commercial end uses. This removes any presumption of a "default fuel" for most new construction; without that presumption, there is no need for a customer to go through a fuel substitution test when designing a new building with all-new end use technologies. There may be some cases in large commercial or industrial new construction where the only available baseline is a different-fuel technology. In that scenario, a default fuel does exist, not because of code but because of previous technology availability. Those projects should be considered fuel substitution and would have to pass the Test.

However, specifying that the Test only applies to retrofit programs does not answer the question of what savings baseline should be used for new construction applications of emerging efficient electric technologies. In those cases, multiple gas and electric appliance standards may apply. Moreover, the minimal market penetration of efficient electric technologies indicates that they are far from the industry standard practices. In that case, one solution would be a "percent of market" savings baseline that changes as the market matures. For example, if the residential new construction market is installing 10% electric heat pumps and 90% gas tank heaters, the correct savings baseline would measure 10% electric-electric savings and 90% gas-electric savings. This could be done by calculating the measure savings from the electric baseline and, separately, from the gas baseline, then adding the adding the results using the market penetration percentages as weights. The calculation would look like this:

Total Savings = $[.10*(\text{Electric}_{\text{Baseline}}\text{-Electric }_{\text{Measure}}) + [(.90*\ \text{Gas}_{\text{Baseline}}\text{-Electric }_{\text{Measure}})]$

The calculation could use BTUs as the common unit for all inputs.

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[22] Previous versions of Title 24 only allowed for an all-electric baseline if a building was unable to be connected to an existing gas distribution line.

c. How should "material environmental impacts" be defined?

"Material environmental impacts" should be defined as increases in GHG emissions as estimated by the *long run* marginal emission values developed for the E3 ACM. Using the long run marginal emission values is the best way currently available to value the GHG profile of California's electricity mix.

Historically, the E3 Avoided Cost Model (ACM) has been used to estimate the *short run* marginal emissions impacts of energy efficiency measures and projects. One key starting assumption in the ACM is that "natural gas is the marginal fuel in all hours."[23] This implies that the resource being avoided by energy efficiency would always be natural gas (adjusted for future RPS requirements, and any marginal renewable generation that impact the day-ahead energy price curves). However, this is no longer the case in California. Because of the state's longstanding and aggressive RPS, any generation that is dispatched to serve the electric use otherwise avoided by energy efficiency could be renewable or gas-fired. This means that it is no longer correct to assume that any added electric load will be served by gas plants only and thus increase total emissions in any time frame longer than the very immediate term.

This trend is expected to intensify as renewable mandates escalate further and renewable prices continue to drop.[24] For instance, 2017 legislation (SB 338) directs utilities to consider non-emitting resources for meeting peak demand. Already in 2017, at several hours of the day, many days of the year, the resource that would be immediately avoided by energy efficiency is solar, which has no carbon emissions. The number of hours where this is the case will only grow as non-emitting resources are put in place to provide grid services that were formerly relegated only to gas peaker plants.

Therefore, it would be more accurate to use an estimate of long run marginal emissions that accounts for current and future renewable resources by aligning the avoided cost calculator with the Integrated Resource Plan proceeding's suggested resource procurement. Using this long run marginal emissions for the third prong is the most reliable way to account for environmental impacts in a state with significant progressive RPS commitments. Successful fuel substitution programs will influence equipment purchases over several years; this equipment will operate for

[23] Energy and Environmental Economics, *Avoided Costs 2018 Update*, May 2018, page 37.
[24] https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

no less than five and sometimes more than 15 years; and, because of the state's aggressive renewable policies, the emissions associated with this new electric equipment will reliably decrease through 2050.

The emissions factor to be used for evaluating the natural gas impact should be the latest published by CARB for the LIWIP program. The standard to be met across the entire the measure life should be:

$$(\mathbf{kWh_{Measure} * LRME^{CO}}) < (\mathbf{BTU_{Best\ Available\ Same\text{-}Fuel\ Alternative} * CO2^{NG}})$$

or

$$(\mathbf{BTU_{Best\ Available\ Same\ Fuel\ Alternative} * CO2^{NG}}) < (\mathbf{kWh_{Baseline} * LRME^{CO}})$$

where:
$LRME^{CO}$ = E3 ACM Hourly Long Run Marginal Emissions Factor
$CO2^{NG}$ = CO^2/BTU Natural Gas combusted in buildings = .000000053MT^{CO2}

i. Should the three-prong test include pollutants, emissions, and changes in resource use, beyond what is calculated in the cost-effectiveness tool, such as potential fluorocarbons released from air conditioning/heat pump systems, sulfur oxides from generation, or increase in water consumption? If so, which specific pollutants, and what is a verifiable source for the data to be used for each pollutant?

This methodology should be kept consistent with all other Commission directives on cost effectiveness. As rules to include various environmental benefits in the TRC and SCT are developed, they should be applied here as well. However, fuel substitution measures should not be screened for any new pollutants not already included in the CET until the Commission begins to account for the on-site environmental impact of all measures (e.g. potential leaks of carbon monoxide from gas water heaters, or refrigerants from refrigerators).

There are important health and equity concerns that make addressing non-GHG pollutants important. Substituting between fuels affects the volume of particulate matter and other air basin-specific pollutants. For example, some ENERGY STAR natural gas water heaters emit more NO_X than others. However, accounting for the impact of new measures or programs on each pollutant is extremely challenging, and likely would complicate program design, review, and approval. This should not slow down the introduction of environmentally beneficial measures – measures that would benefit communities of all incomes across the state. For that reason, the Joint Environmental Parties find that GHG emissions are an adequate proxy for tracking pollutants until improved analytical tools make it feasible to produce more comprehensive analyses for all efficiency measures.

In particular, we recommend that the Commission develop a methodology to assess impacts on the health and well-being of residents. Efficiency measures generally should not have negative impacts on human health by worsening indoor air quality. For example, fossil fuel combustion in household appliances like stoves, water heaters, and furnaces can produce nitrogen dioxide, carbon monoxide, nitric oxide, formaldehyde, acetaldehyde, and ultrafine particles, all of which are harmful to human health.[25] Gas combustion pollutants can cause minor respiratory irritation and as well as more serious conditions; the California Air Resources Board warns that "cooking emissions, especially from gas stoves, have been associated with increased respiratory disease."[26] All efficiency programs, including those that have fuel substitution measures, should demonstrate that the proposed program will not worsen indoor air quality, consistent with protecting public health.

ii. To evaluate environmental impacts, what methodology should be used to make the different pollutants comparable (e.g., assigning a dollar value per ton of each type of pollutant, etc.)? How should the appropriate comparable unit be determined for each pollutant?

This question underscores the complexity of accounting for all pollutant emissions. For that reason, the Joint Environmental Parties recommend that, at this time, the third prong of the Test be limited to changes in GHG emissions.

Question 4. **Is the energy efficiency cost-effectiveness calculator (CET version 18.1) adequate for calculating the cost-effectiveness of potential fuel substitution programs or are modifications needed to the calculator for these programs?**

The CET would need to be updated to automate the heat rate calculations described under question 3a. For prong three, the Commission should ensure the CET GHG emissions outputs are

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[25] *See,* Jennifer Logue *et al.*, "Pollutant Exposures from Natural Gas Cooking Burners: A Simulation-Based Assessment for Southern California" *Environmental Health Perspectives* Vol. 122 No. 1 pp. 43-50, (2013); Victoria Klug and Brett Singer. "Cooking Appliance Use in California Homes—Data Collected from a Web-based Survey." Lawrence Berkeley National Laboratory (August 2011); John Manuel, "A Healthy Home Environment?" *Environmental Health Perspectives*, Vol. 107, No. 7 1999, pp. 352–357; Nasim Mullen *et al.* "Impact of Natural Gas Appliances on Pollutant Levels in California Homes" Lawrence Berkeley National Laboratory, 2012.

[26] California Air Resources Board, "Combustion Pollutants" (reviewed Jan. 19, 2017). Available at https://www.arb.ca.gov/research/indoor/combustion.htm

based on the ACM's long run marginal emissions values, per the Joint Environmental Parties' recommendation. E3 developed hourly long run marginal emission estimates for the 2017 GHG adder interim update of the ACM, as well for other purposes. Other than those adjustments, we are not aware of a further need to modify the CET for cost effectiveness calculation purposes at this time, since the tool already has inputs for savings in therms, kWs, and kWhrs.

However, because some of the most promising fuel substitution technologies involve intricacies that have not been considered before in California, several inputs to the CET will likely have to be re-visited. For example, one of the biggest benefits from electric heat pump water heaters is that they can be programmed to pre-heat water during the hours of the day when solar power is pouring into the electric grid. This load-shaping attribute can help reduce energy and grid operations costs during times of over-supply and reduce the GHG emissions associated with water heating. Yet, none of these benefits will be appropriately evaluated by the CET if the heat pump water heating measure is evaluated according to a standard gas water heating use profile or electric resistance water heater load shape. So, new load shapes will have to be created for these new measures.

It will also be important to discuss how to treat retrofit costs that could be borne by program participants in relation to fuel substitution measures. Measures that replace one fuel with another for the same end use can involve behind-the-meter infrastructure upgrades, such as upgrading a home's electricity panel to allow service to new electric load. In that case, a panel upgrade is necessary to install a new electric heat pump, and in that sense the new panel cost is related to the installation of the new measure. However, a new panel would also be used for a handful of other electric needs that are not related to the measure, and in that sense the panel cost should not be included in the measure's IMC. Additionally, the panel upgrades will endure and support replacement equipment after the installed measure's useful life. For these costs, only a portion of the infrastructure upgrades that are necessary for the measure should be included in the IMC. The Joint Environmental Parties request that the Commission issue clear guidance regarding this type of IMC estimation to avoid conflict during program development. Until such guidance is finalized, we recommend excluding such upgrade costs to avoid underinvesting in energy efficiency.

Question 5. **What is the appropriate efficiency savings accounting for interactive effects related to fuel substitution?**

Interactive effects have long been a contentious issue in California and elsewhere. As is the case with any other measure that could have effects on ambient temperature, interactive effects for fuel substitution measures need to be based on best available data and developed in a transparent way.

While this filing is not the appropriate venue to discuss the detailed literature available on interactive effects for individual fuel substitution measures, it is important to note that interactive effects depend heavily on the type of technology, application, and location. Some of the most promising fuel substitution measures are likely to be installed in garages or other unconditioned spaces. It would be inappropriate to calculate interactive effects for those cases. For example, since most water heaters in California single-family home are located in garages, the majority of electric heat pump water heaters will be installed in the same unconditioned space. There will also be minimal interactive effects for heat pump water heaters installed indoors but ducted to outdoors, as is the likely case for multifamily applications.

There are multiple complexities involved in determining interactive effects for any one technology or application. For that reason, the Joint Environmental Parties recommend that more analysis be done to answer this question, and that interactive effects not be included for fuel substitution programs until that analysis is complete. We also suggest that the California Technical Forum (Cal TF) is the appropriate forum to discuss the technical matters at issue here.

Question 6. **How should fuel substitution programs be funded?**

a. Should energy efficiency funds from natural gas customers pay for programs to substitute electricity with natural gas, and electricity customers pay to substitute natural gas with electricity? Or vice versa?

Within the realm of energy efficiency programs, the question of funding is largely one of accounting and practicality. The Commission can deliberate about how to spread efficiency costs across customer classes or single-fuel utilities, but the reality is that a dollar invested in reducing energy use reduces system and fuel costs for *all* IOU customers. With the limited exception of POU or other non-IOU customers, most Californians rely on the same gas and electric distribution system, even in areas that are served by single-fuel IOUs or community choice aggregators (CCAs). In regions with CCAs, the efficiency program funding still comes from the “distribution” side of the bill. Efficiency programs are truly a shared resource for any customer using gas and electric IOU infrastructure. The problem is whether utilities are sufficiently motivated to pursue these programs even when there are significant energy and GHG savings to be gained.

There are several possible options for funding fuel substitution. One is to fund it through “original fuel” program dollars, in which case the original fuel utility would be credited with the savings. In single-fuel utility territories, either utility should be allowed to run these programs, with the original fuel utility compensating the “new fuel” utility for any efforts that would result in original fuel savings. A second option is to fund programs through new fuel utility program funds, in which case that utility would have to be credited for the resulting savings. The conversion of savings goals from one fuel to another could leverage the BTU-based methodologies already being considered by the CEC. In that case, the achieved fuel substitution savings would have to be backed-out of the original fuel utility’s goals. This last step is necessary because the fuel substitution savings would have been achieved and they would therefore no longer be available for the original fuel utility to pursue.

Fuel substitution savings are a real, significant opportunity for California. What matters most is creating rules that encourage program administrators to go after those savings, not how we choose to fund those efforts across arbitrary funding stream lines. Therefore, both options discussed above should be made available to all program administrators, including community choice aggregators, so that the state can benefit from these promising savings.

In addition, the Commission should consider bidding out fuel substitution program opportunities to third parties, particularly where a statewide program design may be most appropriate such as with midstream and upstream programs. In this way, efficiency program funds can be pooled from multiple IOUs (even potentially from both fuels) and programs can be designed and implemented by third parties that may have less internal or other conflicts related to fuel substitution. The Commission should initiate this request for proposals from third parties, rather than waiting for a IOU to take the initiative, so that beneficial fuel substitution programs can make progress.

b. What impact do these considerations have on cost effectiveness calculations, if any?

As discussed in the last question, the issue of funding is a question of accounting. The funding *mechanism* for a program should have no effect on a measure or program's cost effectiveness. Therefore, the question of funding should also not be used to justify imposing unreasonably restrictive cost effectiveness requirements on fuel substitution.

Question 7. **How should each prong of the three-prong test account for electricity generated on-site? Should the method vary depending on the on-site generation fuel type?**

No comment. The Joint Environmental Parties may respond to this question in reply comments.

IV. Stakeholder Support

In addition to the parties filing this motion – NRDC and Sierra Club – the following 18 stakeholder organizations have agreed to sign on in support of these comments:

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V. Conclusion

The Joint Environmental Parties appreciate the Commission's response to our motion to review the Test and the opportunity to provide these comments. There are several complex and technical issues involved in reconsidering the Test – we urge the Commission to organize a public workshop to discuss key issues that arise from parties' comments.

Dated: July 17, 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

NOTICE OF EX PARTE COMMUNICATION OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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Counsel to
California Community Choice Association

July 20, 2018

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

NOTICE OF EX PARTE COMMUNICATION OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Pursuant to Rule 8.4 of the California Public Utilities Commission (CPUC) Rules of Practice and Procedure, the California Community Choice Association (CalCCA) hereby gives notice of the following ex parte communication on the Power Charge Indifference Adjustment rulemaking.

This communication was initiated by Evelyn Kahl, Counsel to CalCCA, on behalf of CalCCA. The communication occurred on July 18, 2018, from 10 a.m. to 10:30 a.m. in person at the Commission's offices with John Reynolds, Advisor to Commissioner Carla Peterman, Mitchell Shapson, attorney for the Commission. Nathaniel Malcolm, Marin Clean Energy, attended in person, and Beth Vaughan, CalCCA's Executive Director, participated by telephone.The discussion outline for the meeting is attached to this Notice.

Ms. Kahl followed up with Messrs. Reynolds and Shapson on July 20, 2018, by email, directing their attention to CalCCA's opening brief beginning on page 46. This section of the brief discusses the Commission's view, expressed in its annual Padilla Report on the renewable portfolio standard, that utility resources should be valued using long-term, rather than short-term, price referents.

To obtain a copy of this ex parte notice, please contact:

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Respectfully submitted,

Evelyn Kahl

EVELYN KAHL
Counsel to
California Community Choice Association

July 20, 2018

Attachment

Power Charge Indifference Adjustment – R.17-06-026

California Community Choice Association

July 18, 2018

R.17-06-026

Central Mission

- ✓ Determine and allocate stranded costs to prevent cost shifts in a way that complies with statute and is scalable over time
- ✓ Redistribute utility resources to align supply with bundled demand and make resources available to CCAs and ESPs
- ✓ Reduce portfolio costs and prevent further stranded cost accumulation

PCIA Calculation

NET PORTFOLIO COSTS − PORTFOLIO VALUE = STRANDED COSTS

Key Statutory Boundaries
Cost Shifts

- "The implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation." §366.2(a)(4)
- **To avoid cost shifts, the Commission may allocate to CCA customers the "*estimated net unavoidable electricity purchase contract costs attributable to the customer" …."reduced by the value of any benefits that remain with bundled service customers reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits ….* §366.2(f)(2), (g)**
- "[A]ny incremental [post –SB 350] renewable energy integration resources…." §454.51(c), provided that CCAs may self-provide
- "[A]dditional [post-SB 350] procurement is authorized for the electrical corporation in the integrated resource plan or the procurement process …." §454.52(c)
- "Bundled retail customers of an electrical corporation shall not experience any cost increase as a result of the implementation of a community choice aggregator program. 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." §366.3.

Key Statutory Boundaries
CCA Procurement Autonomy

"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." §366.2(a)(5)

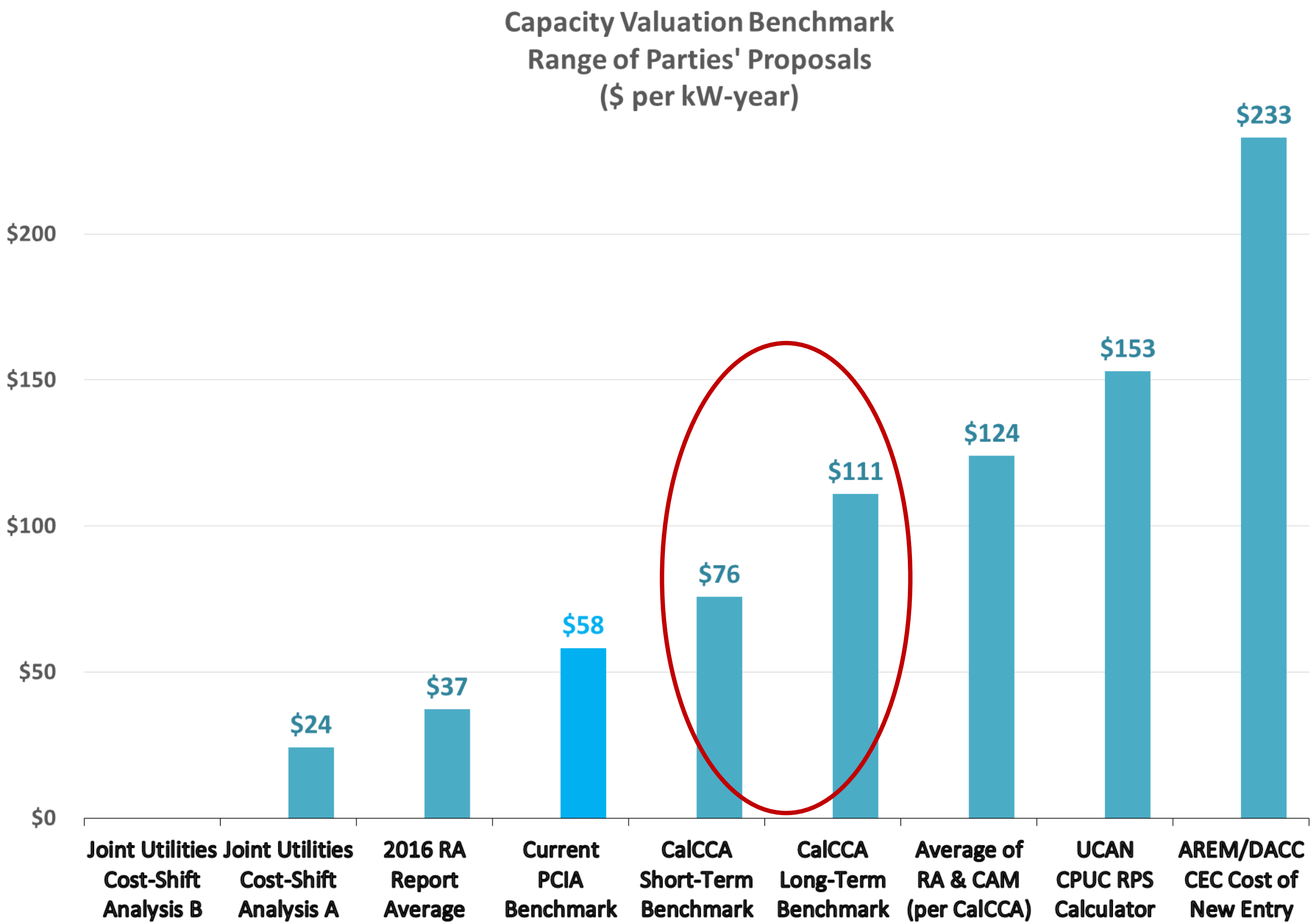
- ✓ Modify Current Methodology for implementation on January 1, 2019, as a bridge to a more durable solution, recognizing additional value that is inherent in the supply portfolio for:
  - Long-term resource value and price risk hedging value
  - GHG-free resource attribute value
  - Ancillary services products

- ✓ Develop and implement “Staggered Portfolio Auction” of all utility RPS and GHG-free resources by 1Q 2020 and complete by 4Q 2021
  - Realigns utility supply and bundled demand using a voluntary market mechanism
  - Makes PCIA-eligible supply available to non-utility LSEs
  - Reveals a more reliable and reasonably representative market price to benchmark any remaining supplies during 2-year auction process

- ✓ Reduce portfolio costs and improve portfolio management
  - Securitization
  - Buydown and securitization
  - Forecasting of departing load
  - Active Portfolio Management and forward sales practices

CalCCA Proposal

Solving the $50 Billion Problem


Capacity Valuation Benchmark
Range of Parties' Proposals
($ per kW-year)
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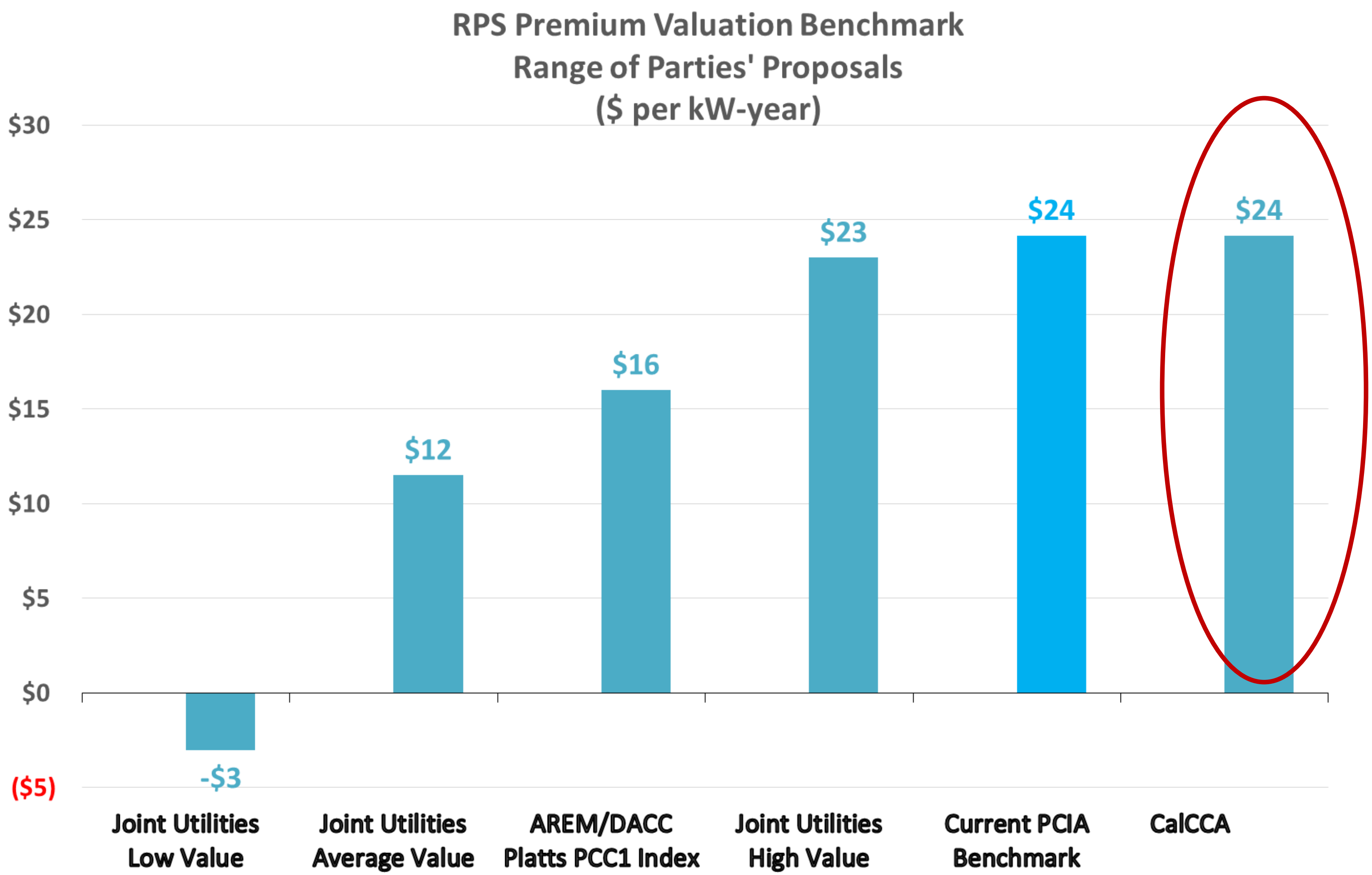
$76
$111
$124
$153
$233
Joint Utilities Cost-Shift Analysis B
Joint Utilities Cost-Shift Analysis A
2016 RA Report Average
Current PCIA Benchmark
CalCCA Short-Term Benchmark
CalCCA Long-Term Benchmark
Average of RA & CAM (per CalCCA)
UCAN CPUC RPS Calculator
AREM/DACC CEC Cost of New Entry


RPS Premium Valuation Benchmark
Range of Parties' Proposals
($ per kW-year)
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$25
$20
$15
$10
$5
$0
($5)
-$3
$12
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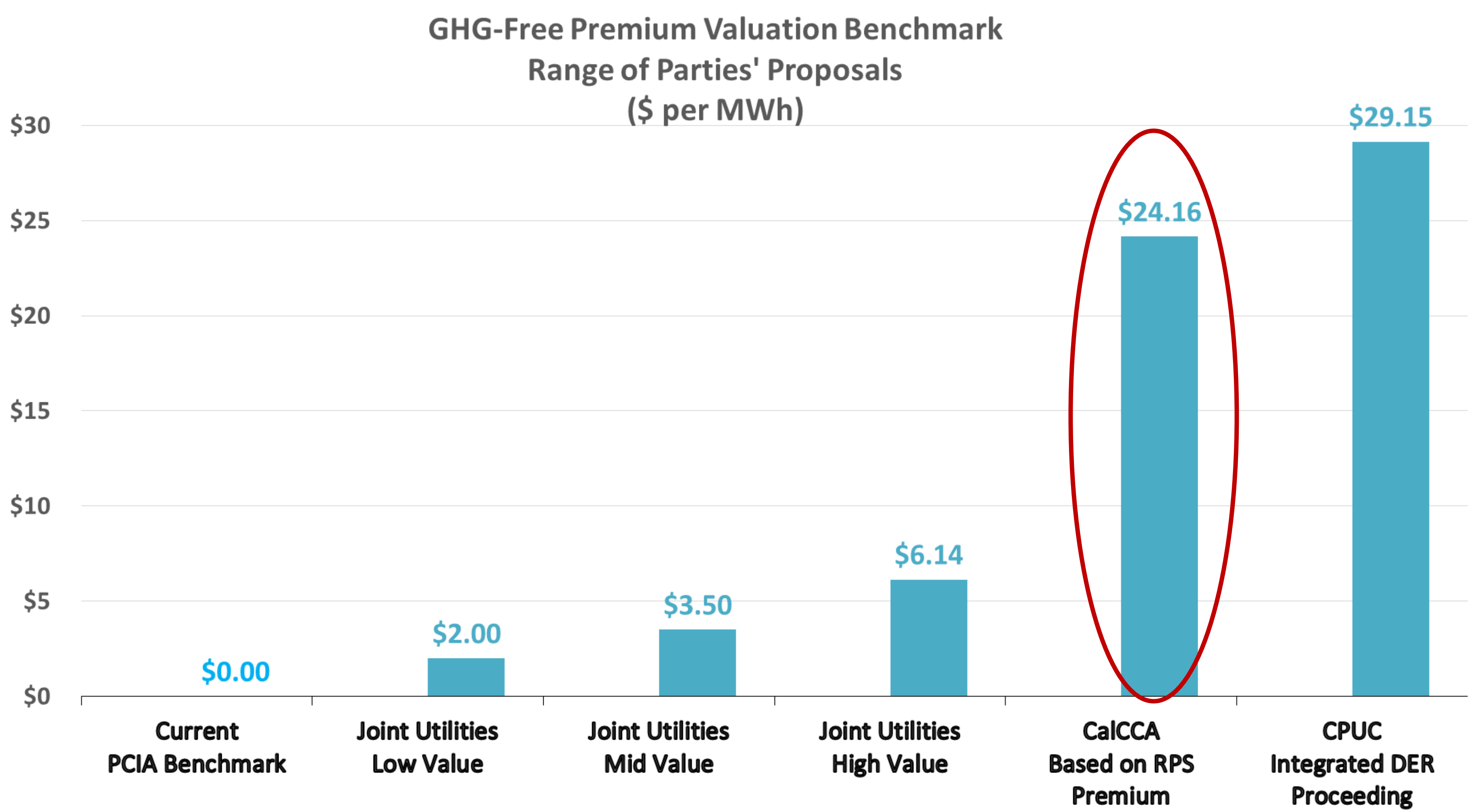
$24
Joint Utilities Low Value
Joint Utilities Average Value
AREM/DACC Platts PCC1 Index
Joint Utilities High Value
Current PCIA Benchmark
CalCCA


GHG-Free Premium Valuation Benchmark
Range of Parties' Proposals
($ per MWh)
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$25
$20
$15
$10
$5
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$2.00
$3.50
$6.14
$24.16
$29.15
Current PCIA Benchmark
Joint Utilities Low Value
Joint Utilities Mid Value
Joint Utilities High Value
CalCCA Based on RPS Premium
CPUC Integrated DER Proceeding

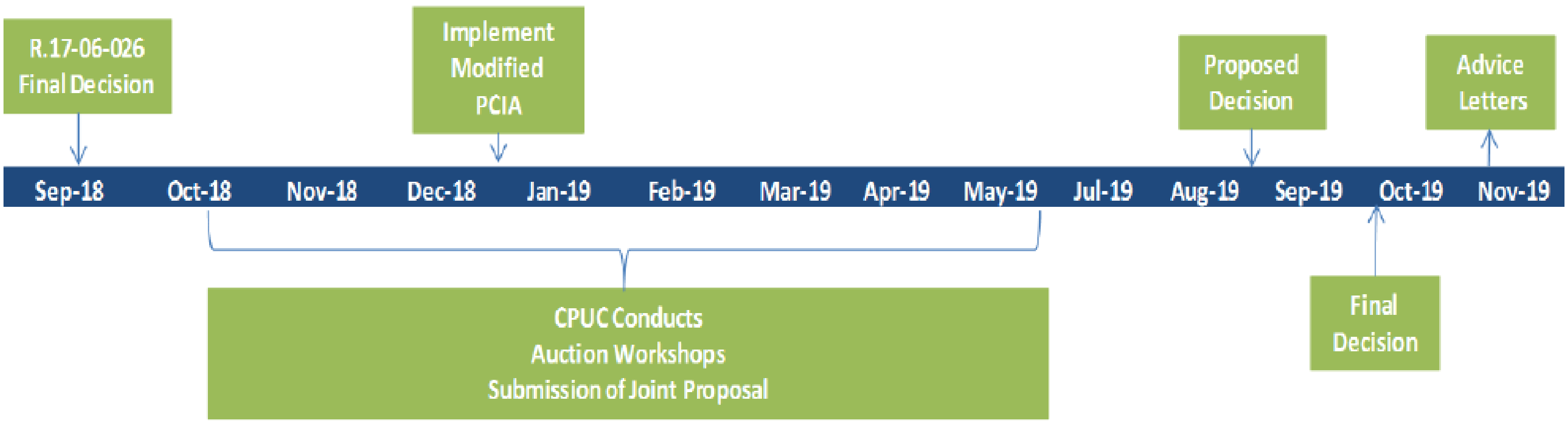
Details of Staggered Portfolio Auction

- ✓ All utility RPS and GHG-free resources to be auctioned
- ✓ Quarterly auctions begin by Q2 2020 and complete by Q4 2021
- ✓ Quarterly auctions allow for adjustments based on initial market response
- ✓ Products, terms and conditions mirror utility resources and contracts as closely as possible
- ✓ All market participants are eligible to participate
- ✓ Expertise of outside resources anticipated to determine precise timing and structure of offerings

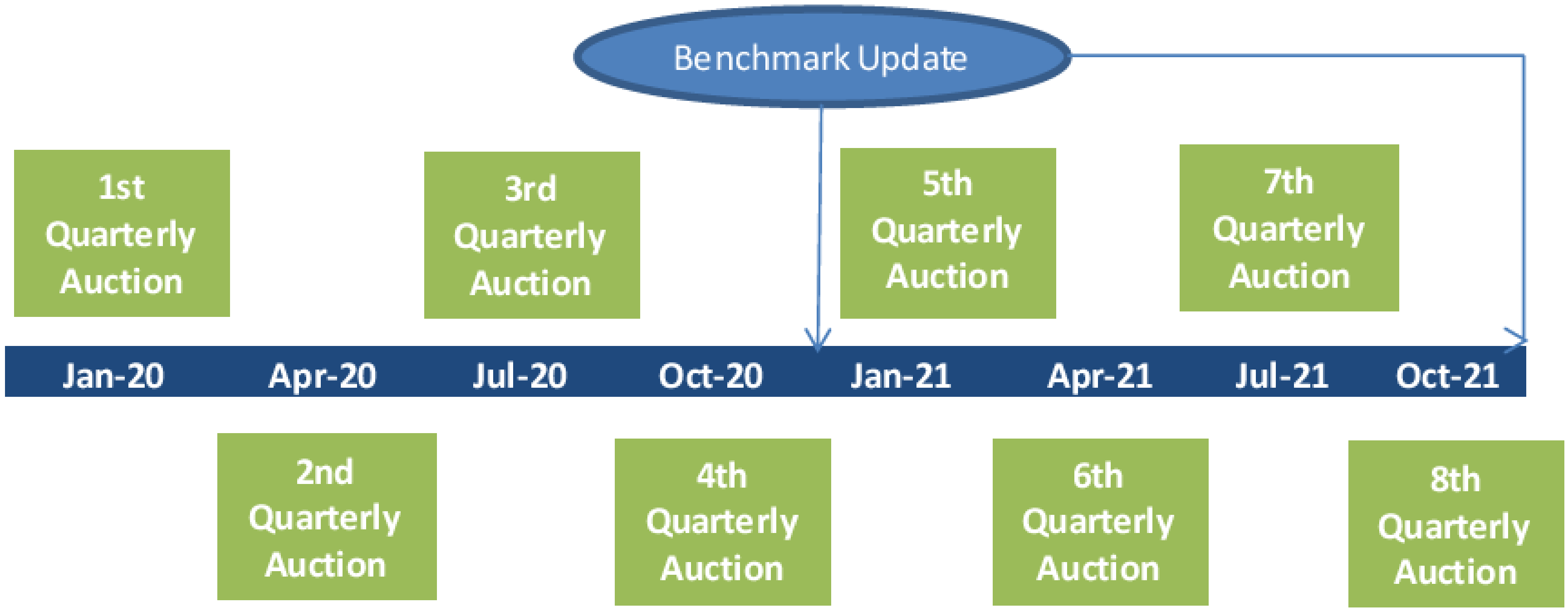
Benefits of a Staggered Portfolio Auction

- Realigns utility supply and bundled demand using a voluntary market mechanism
- The market sets the value of the portfolio products/attributes and allocates the portfolio resources to the participants that value them the most
- All value components of utility portfolios are captured in the auction price
- CCAs maintain control of procurement, consistent with the statutory requirement
- Utilities do not control CCA resources or gain unfair competitive advantage
- Double procurement is reduce or eliminated
- Makes PCIA-eligible supply available to non-utility LSEs to ensure maximum value in the auction
- Reveals a more reliable and reasonably representative market price to benchmark any remaining un-auctioned supplies
- Provides certainty and finality in determining above-market costs and customers' bill impacts

Near-Term Implementation Steps



End-State Implementation



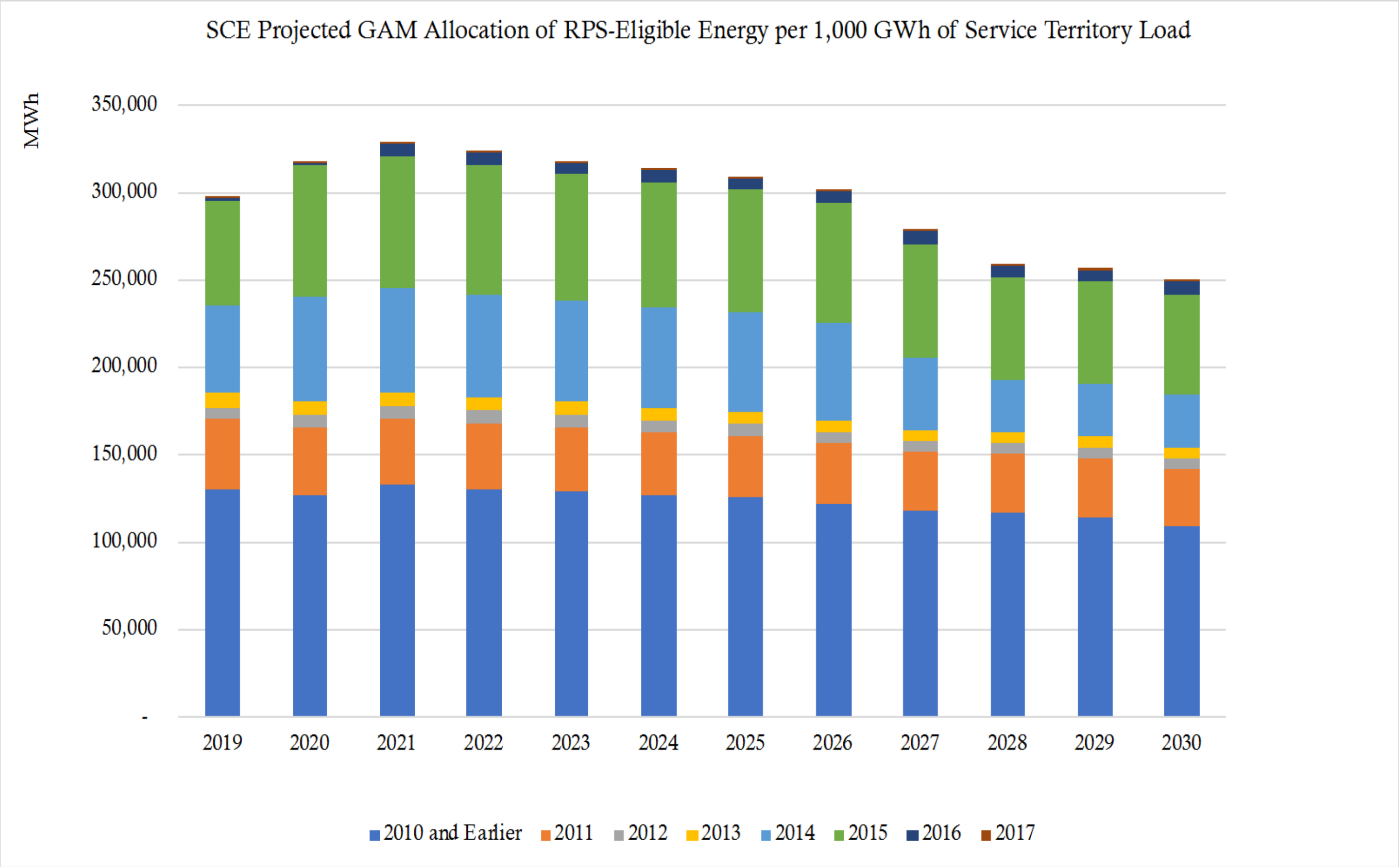
Flaws in Joint Utilities' GAM/PMM

- Impairs a CCA's right to be "solely responsible" for procurement on behalf of its customers in violation of the statute; Joint Utilities did not analyze impacts on LSEs
- Contravenes statutes governing definition of departing load cost responsibility and impermissible cost shifts
- Requires CCAs to continue to double procure in order to meet 10 year RPS requirements – utilities only estimate volumes available to CCAs for 1 year and can sell or dispose of them at any time and without notice
- Prevents effective CCA portfolio risk management and is anti-competitive:
  - After-the-fact monthly/quarterly allocation of RA and REC attributes and energy settlements
  - Imposes an involuntary resource allocation that presents LSEs with un-hedgeable position in spot market
  - Utilities maintain superior and inequitable access to information regarding availability and dispatch of resources; utilities control availability and bidding of resources

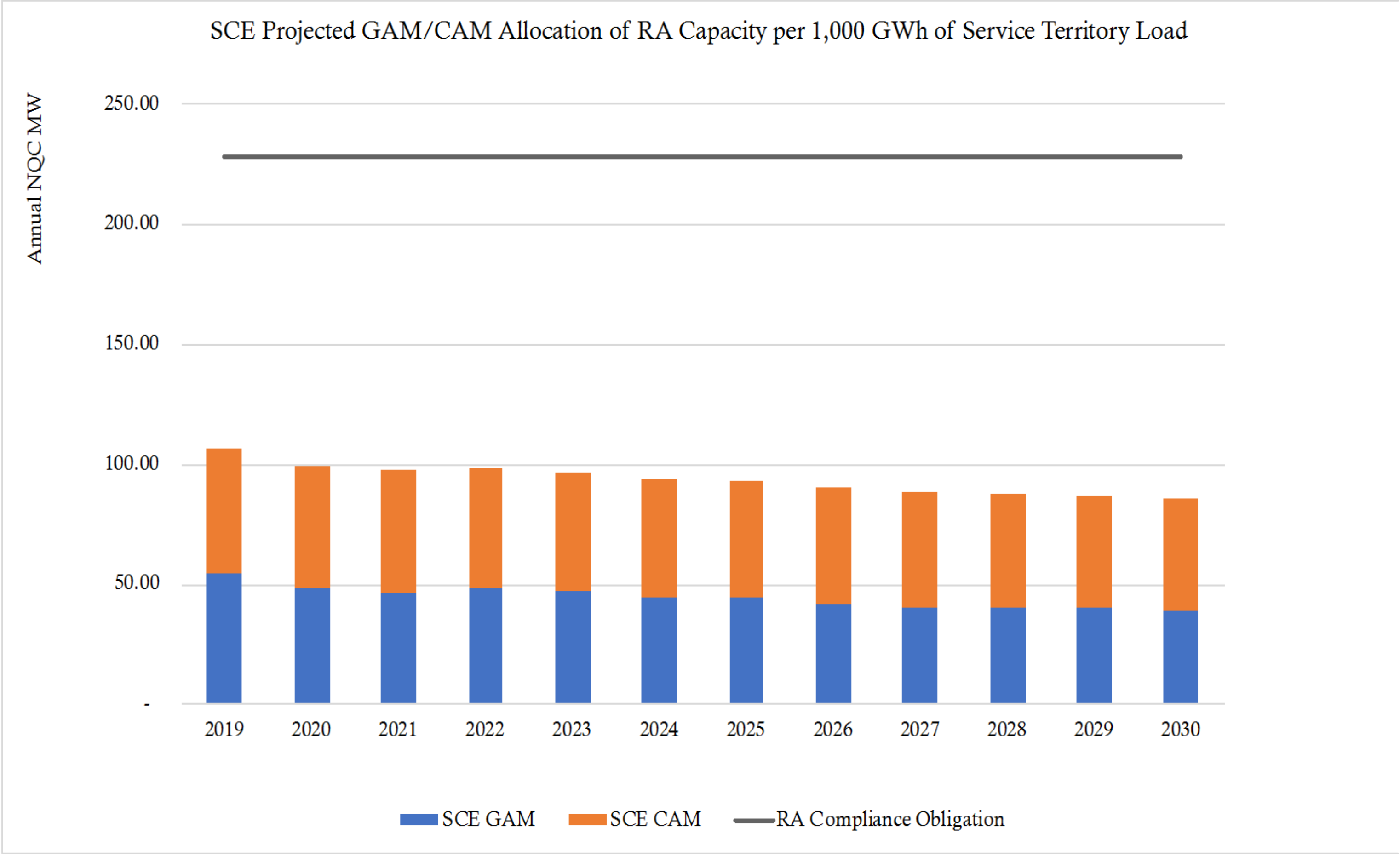
Flaws in Joint Utilities' GAM/PMM (cont'd)

- Reduces CCA incentives to build new resources and enter into long-term contracts
- Increases CCA reliance on spot energy markets
- At odds with IRP's clean net short methodology and presents issues under CEC Power Content Label methodology
- Devalues RPS portfolio value under current law by unbundling the RPS attribute from the energy attribute in bundled RPS purchases, thereby threatening ongoing eligibility for PCC1 treatment
- Furthers market dysfunction by allowing three for-profit utilities to control and manage substantial portion of resources relied upon by CCAs (e.g., 85% supply, 15% load) and an untenable competitive landscape for the CCAs
- Undermines the development of functional RA and RPS markets
- Too many complications for near-term implementation

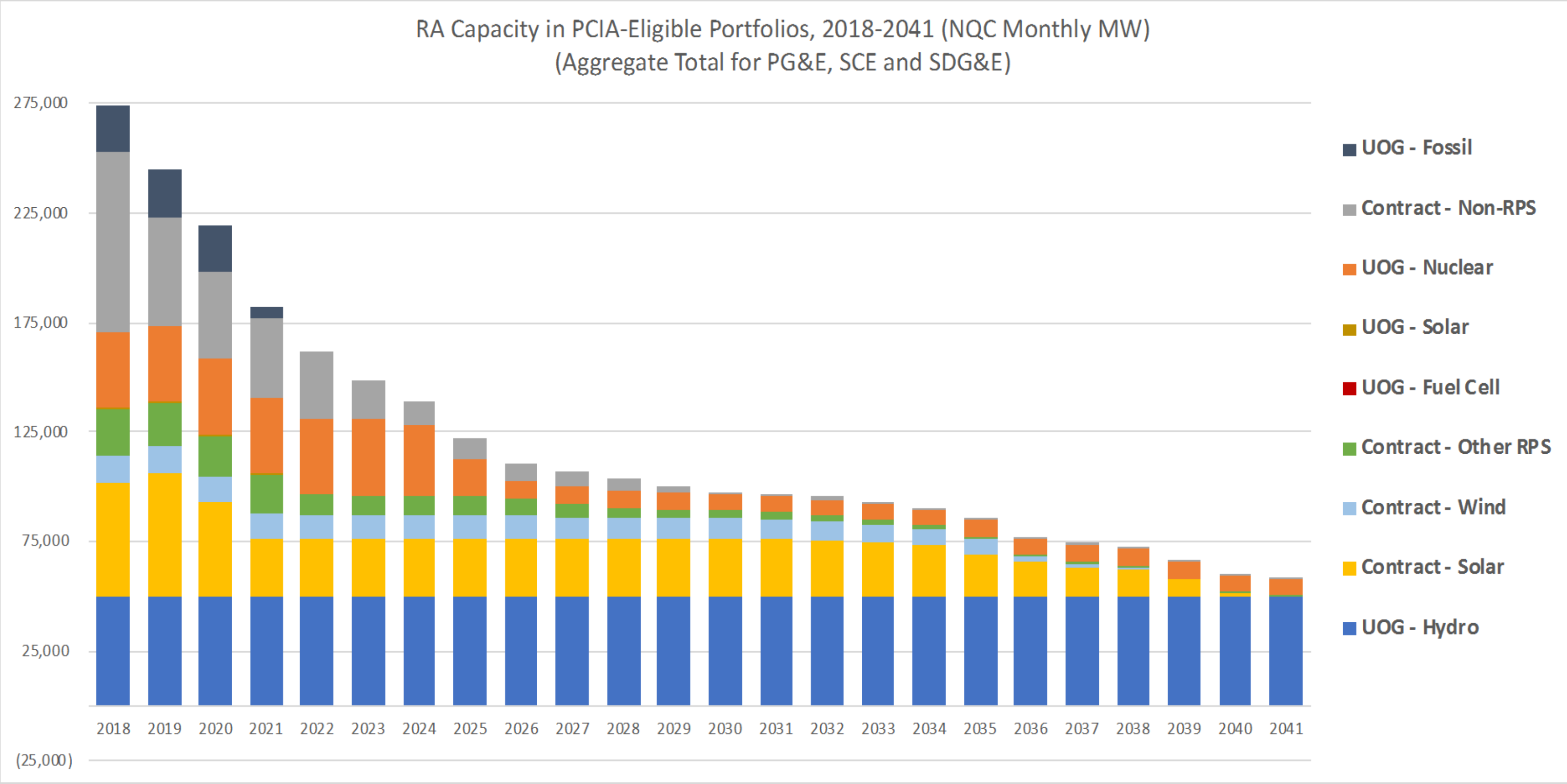
A vintage 2017 CCA in SCE's service territory would, in 2020, receive an allocation of over 317,000 MWh of RPS-Eligible Energy, or 96% of its 33% RPS compliance obligation for 2020.



A vintage 2017 CCA in SCE's service territory would, in 2020, receive an allocation of System RA Credit under the GAM; combined with the existing CAM allocation, this would represent 44% of the CCA's RA compliance requirements

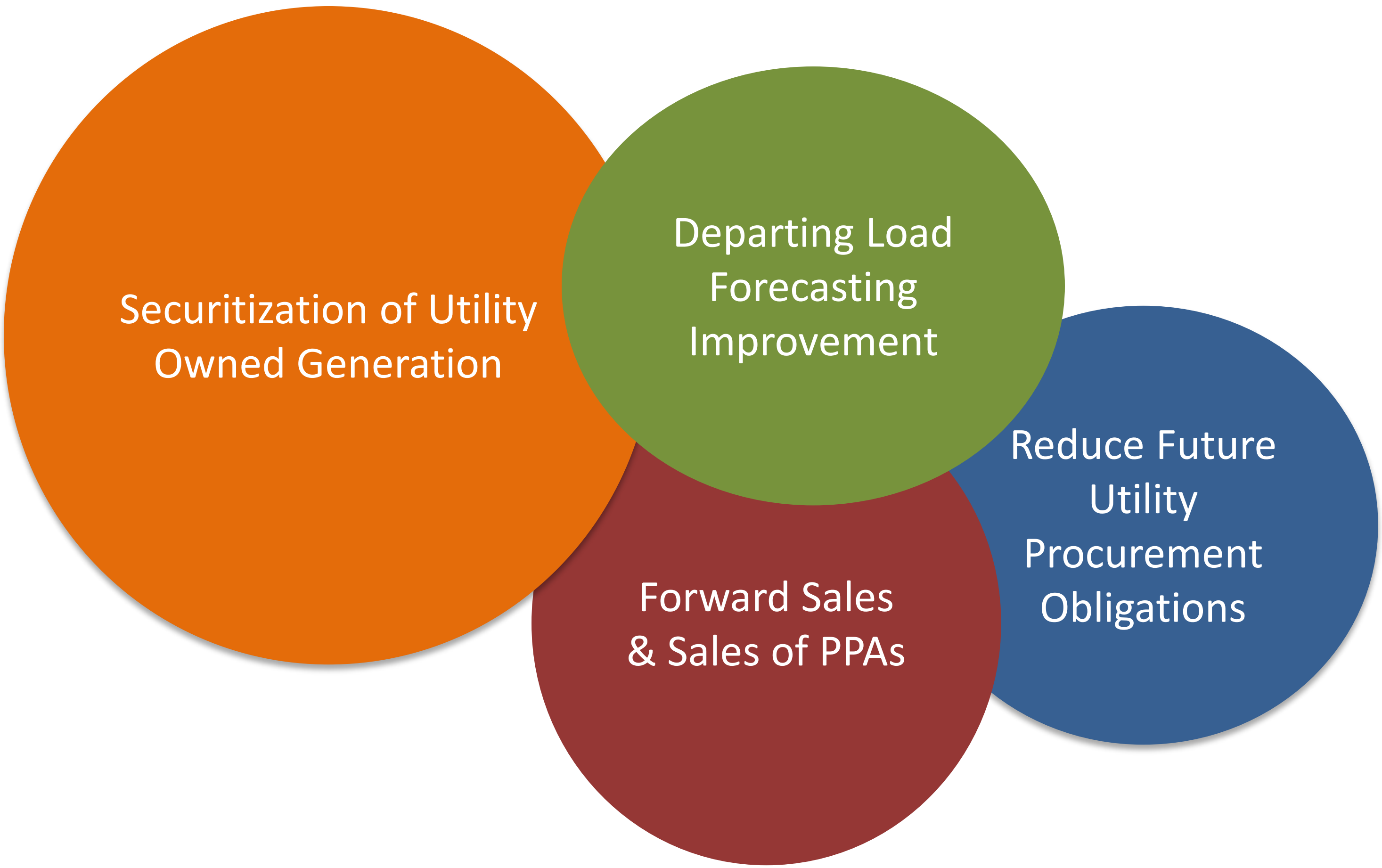


PCIA-Eligible RA Resources



Source: Aggregated Summary Exhibit IOU-5

Portfolio Cost Reduction



Application: 16-11-005

Exhibit: CalCCA-02

Date: July 18, 2018

Witness: Hilary Staver

REBUTTAL TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

ADVANCING LOCAL ENERGY CHOICE cal-cca.org

Joint Application to Establish Non-Bypassable Charge ("NBC") for Above-Market Costs Associated with Tree Mortality Power Purchase Agreements ("Tree Mortality") in Compliance with Senate Bill 859 and Resolution E-4805.	)))))))	Application No. 16-11-005 (Filed November 14, 2016)

REBUTTAL TESTIMONY OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

I. INTRODUCTION

In accordance with the *Scoping Memo and Ruling of Assigned Commissioner,* dated May 30, 2018 ("Scoping Memo"), the California Community Choice Association ("CalCCA") submits the following rebuttal testimony. In an email ruling, dated June 18, 2018 ("Procedural Ruling"), assigned Administrative Law Judge ("ALJ") Patrick Doherty granted an extension of time to and including July 18, 2018 to serve rebuttal testimony.

This proceeding has been established "to establish a non-bypassable charge for above-market costs associated with tree mortality power purchase agreements in compliance with Senate Bill 859 (Committee on Budget and Fiscal Review, 2016) and [California Public Utilities Commission ("Commission")] Resolution E-4805."[1] In order to determine "above-market" costs, the Commission must determine a ***value*** for the various attributes associated with the tree mortality power purchase agreements ("Tree Mortality PPAs"). The Scoping Memo provides guidance in this regard: "In all testimony, the [investor-owned utilities ("IOUs")] must…provide information on the actual energy, capacity and renewable energy credit ***values*** created by these [Tree Mortality PPAs] and how they are being apportioned to their bundled ratepayers."[2] The

[1] Scoping Memo at 1-2.

[2] Scoping Memo at 3.

Scoping Memo accentuated this requirement by clarifying that "[t]his means that testimony from the [IOUs] must characterize every element of the asserted…benefits of the NBC…."[3]

On June 28, 2018, in accordance with the Procedural Ruling, the IOUs submitted their prepared testimony. With respect to "capacity" or resource adequacy ("RA") value, the IOUs do not propose to monetize this value and net this monetized amount from overall costs to determine above-market costs associated with the Tree Mortality PPAs. Instead, the IOUs propose that "each retail seller would receive its proportional share of the RA credit arising from each of the [Tree Mortality PPAs]."[4] The IOUs justify this approach as follows: "As there is not an established RA market for capacity, in contrast to the established energy market, this proposal is fair and relatively easy to administer, as the Joint IOUs use this method for the [Cost Allocation Methodology ("CAM")].[5] The IOUs' proposal for determining RA value differs from the IOUs' proposal for determining renewable energy credit ("REC") value. With regard to REC value, the IOUs propose to monetize the value, and the IOUs justify this approach as follows: "The proposal for the IOUs to monetize and retain the value of the REC attributes rather than allocate them to benefiting [load-serving entities ("LSEs")] is the most administratively efficient solution to share the benefits of the renewable procurement, given the limited duration of the contracts (5-years) and small size of the procurement relative to the Joint IOUs total portfolio."[6]

CalCCA's rebuttal testimony briefly addresses two flaws in the IOUs' proposal for determining and applying RA value associated with the Tree Mortality PPAs. First, as further described below, the period of time under the Tree Mortality PPAs has largely expired for

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[3] Scoping Memo at 3-4.

[4] Exhibit Joint IOU-02 at 8:9-10.

[5] Exhibit Joint IOU-02 at 10:19-21.

[6] Exhibit Joint IOU-02 at 9; note 14.

realizing value from any proposed transfer of RA credits. In other words, since RA credits only have value if they can be used on a ***month-ahead*** or ***year-ahead*** basis for compliance purposes, and since a significant number of months under the Tree Mortality PPAs has lapsed, there is no practical way for LSEs, like Community Choice Aggregators, to realize value from these expired RA credits. The value of these expired RA credits inures solely to the IOUs and bundled customers. As such, monetization ***must*** occur for at least these expired RA credits. While generally recognizing this limitation,[7] the IOUs advance no valuation methodology in their testimony with respect to this monetization.

Second, the same justification given by the IOUs for monetizing REC value applies to monetizing RA value, yet the IOUs apply different methodologies. Specifically, "given the limited duration of the [Tree Mortality PPAs] (5-years) and small size of the procurement relative to the Joint IOUs total portfolio," monetization of RA should also be used as the basis for determining RA value.[8] This justification is enhanced for RA purposes by the fact that the "duration" of the Tree Mortality PPAs is no longer five years. As further described below, the five-year term of the Tree Mortality PPAs started in 2017, and for year-ahead RA purposes it is likely that any transfer of RA credits would only apply for two full compliance years.

II. REBUTTAL TESTIMONY

In their testimony, the IOUs do not specifically describe or address a significant limitation with their RA valuation proposal. The IOUs likewise did not address this limitation at

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[7] *See* Exhibit Joint IOUs-02 at 8; note 13.

[8] *See* Exhibit Joint IOUs-02 at 9; note 14.

all as part of their formal presentation at the December 12, 2017 workshop in this proceeding.[9] In order for the IOUs' RA valuation proposal to provide ***any*** benefit to Community Choice Aggregation ("CCA") customers, the proposed transfer of RA credits to Community Choice Aggregators must occur in time to be used for compliance purposes by Community Choice Aggregators.

RA credits are applied on a month-ahead and year-ahead basis.[10] As detailed by the IOUs, the Tree Mortality PPAs began delivering energy as early as February 1, 2017 and as late as December 2, 2017.[11] As such, for the period from February 1, 2017 until the first compliance month in which the RA credits can be used by Community Choice Aggregators, RA credits from the Tree Mortality PPAs will have no value at all to Community Choice Aggregators (and CCA customers). Given the procedural schedule set forth in this proceeding, it is unlikely that a final decision will be issued until the first quarter of 2019.[12] "Due to the complexity and number of issues in this proceeding," however, a final decision may not be issued until later in 2019.[13] After the issuance of a final decision, certain implementation activities must also occur in order

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[9] See Appendix B to the Administrative Law Judge's Ruling Entering Energy Division Staff Proposal Into The Record And Seeking Party Comments, dated April 17, 208 ("ALJ Ruling").

[10] *See generally 2018 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings* (revised February 5, 2018) ("RA Guide") at 4-5. (A copy of the RA Guide is available at: www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454920 . By October 31, LSEs are required to make a year-ahead RA compliance showing, and 45 days prior to the compliance month, LSEs are required to make month-ahead RA compliance showing. (RA Guide at 4-5.)

[11] *See* Exhibit Joint IOUs-02; Appendix A-1.

[12] *See* Scoping Memo at 7. *See also* Rule 14.2 (issuance of recommended decision).

[13] *See* Scoping Memo at 8.

to transfer RA credits.[14] As such, for practical purposes, it is unlikely that the IOUs would be able to transfer RA credits for ***year-ahead*** purposes until compliance-year 2020.[15] By this time, the Tree Mortality PPAs will ***not*** have a duration of five years, but in some cases will only have a remaining duration of slightly over two years.

The IOUs rely "on the limited duration of the [Tree Mortality PPAs] (5-years)" as a basis for recommending monetization of REC value.[16] While this is persuasive with respect to contracts having a duration of five years, it is even more persuasive with respect to contracts having a remaining duration of two years. The Commission should consider the extremely limited remaining duration of the Tree Mortality PPAs when it determines how to value RA attributes. This consideration will, in CalCCA's view, lead to a conclusion that RA value should be determined by monetizing the RA attributes, not by transferring RA credits to Community Choice Aggregators. In any event, even if the Commission determines that RA credits should be transferred for the remaining duration of the Tree Mortality PPAs, an RA value must be determined ***by monetization*** during the period from February 1, 2017 through the first compliance period in which the RA credits have practical effect.

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[14] For example, with respect to RA credits associated with CAM resources, I understand that the Commission's Energy Division must first determine each LSE's pro-rata share of CAM allocations for use in compliance filings, and must transmit this information via a letter to each LSE. Presumably this process or a similar one would be followed if the Commission were to adopt the IOUs' RA valuation proposal.

[15] As noted above, in order to be useful for year-ahead purposes, the RA credits must be allocated and available for the October 31 compliance filing. (*See* note 10, above, referencing the RA Guide at 4.) As such, since a final decision in this proceeding is not expected to be implemented prior to October 31, 2018 (for compliance-year 2019), the first compliance year is 2020 that RA credits could be allocated and available.

[16] *See* note 6, above (referencing Exhibit Joint IOU-02 at 9; note 14).

In its prepared testimony (and its December 12, 2017 workshop presentation ("CalCCA Presentation"), CalCCA proposed a RA valuation methodology that involves monetization. In short, CalCCA believes that "the current [Power Charge Indifference Amount ("PCIA")] methodology for valuing RA [should be used] until that methodology changes, whereupon the new methodology should be used."[17] CalCCA also expressed support for using the ***new*** PCIA methodology for the ***entire*** 5-year period, since the IOUs' tree mortality procurement costs are currently being accounted for in memorandum accounts, which allows for true-up and final accounting before customers pay the costs through rates.[18]

While CalCCA still believes that using the PCIA methodology for valuing RA under the Tree Mortality PPAs is the best approach, CalCCA is not opposed to using current RA prices for valuation and monetization purposes. Various sources of information on current RA prices are available. First, CalCCA notes that one of the ALJs in this proceeding could issue a ruling similar to the one ALJ Doherty recently issued seeking price information on RECs.[19] In the REC Price Ruling, ALJ Doherty directed the IOUs to serve "information on the prices for RECs established as part of the IOUs' 2018 solicitations for the sale of RPS-eligible generation and associated RECs.[20] CalCCA observes that the IOUs have similarly submitted various advice letters in 2018 describing, under seal, information on RA prices that have resulted from "arms-

[17] Exhibit CalCCA-01 at 4 (citing CalCCA Presentation at 6).

[18] *See* Exhibit CalCCA-01 at 4:17-18 (referencing Resolution E-4805 at 17; Conclusions of Law 9 and 10).

[19] *See Administrative Law Judge's Ruling Seeking Additional Information From Parties On Pricing Of Renewable Energy Credits*, dated July 9, 2018 ("REC Price Ruling") (A.16-11-005).

[20] REC Price Ruling at 3 (referencing, among other things, information presented by Pacific Gas and Electric Company ("PG&E") in PG&E's Advice Letter 5294-E, filed on May 16, 2018.

length transactions" for RA.[21] CalCCA notes that the following RA-related advice letters were filed in 2018 and that, similar to REC transactions, the prices for RA revealed by these transactions may be useful in constructing an administrative benchmark value for RA in this proceeding.

On March 15, 2018, PG&E submitted Advice Letter 5252-E relating to RA cost responsibility associated with an RA transaction between PG&E and Silicon Valley Clean Energy Authority.[22]

On April 16, 2018, PG&E submitted Advice Letter 5275-E relating to RA cost responsibility associated with an RA transaction between PG&E and King City Community Power.[23]

On May 9, 2018, Southern California Edison Company ("SCE") submitted Advice Letter 3801-E relating to RA cost responsibility associated with an RA transaction between SCE and Desert Community Energy.[24]

Second, the Energy Division routinely collects pricing information on RA-related transactions. An aggregated summary of this pricing information is usually provided in so-called annual Resource Adequacy Reports.[25] The 2016 Resource Adequacy Report was issued in June

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[21] *See* REC Price Ruling at 3 ("Because this process results in a series of arms-length transactions for RECs that leads to the establishment of a price for those RECs, the prices for the RECs revealed by these transactions may be useful in constructing an administrative benchmark value for the RECs at issue in this proceeding.").

[22] PG&E Advice Letter 5252-E was approved by the Energy Division on April 18, 2018, effective March 15, 2018.

[23] PG&E Advice Letter 5275-E was approved by the Energy Division on May 14, 2018, effective April 16, 2018.

[24] SCE Advice Letter 3801-E was approved by the Energy Division on June 14, 2018 in a non-standard disposition letter.

[25] The annual Resource Adequacy Reports are available at http://cpuc.ca.gov/RA/.

2017, and CalCCA understands that the 2017 Resource Adequacy Report will be issued later this month.

Prices for RA revealed in these reports may be useful in constructing an administrative benchmark value for RA in this proceeding. A cautionary note may be appropriate, however, about past prices for RA. The Energy Division issued a paper earlier this year that describes various trends with respect to RA, some of which portends an increase in RA costs in 2018 and beyond.[26] The Energy Division Report describes the following trend with respect to RA, observing that deficiencies in RA are beginning to emerge:

> Prior to the 2018 year ahead RA process, LSEs had only ever filed two local waivers with CPUC. However, in September and October of 2017 several LSEs began contacting Energy Division staff regarding the inability to procure adequate local and system capacity. Of the twenty-seven LSEs that submitted year ahead 2018 RA filings on October 31, 2017, eleven filed waiver requests to cover local deficiencies totaling roughly 270 MW. In addition, the year ahead filings identified a collective deficiency of around 40 MW in system capacity.[27]

Presumably these deficiencies will result in increases to RA prices. As such, the Commission should exercise caution in taking RA-related pricing information in the 2016 and 2017 Resource Adequacy Reports and simply extrapolating that information.

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26 *See* Energy Division staff report (*Current Trends in California's Resource Adequacy Program,* dated February 16, 2018) ("Energy Division Report"), available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457193.

27 Energy Division Report at 43.

Finally, CalCCA understands that Community Choice Aggregators recently provided pricing and contract information to the Energy Division in response to data requests from the Energy Division. (CalCCA understands that other LSEs also provided this information.) The distribution of this information under seal was facilitated by the issuance in R.17-09-020 of a ruling, dated May 18, 2018, authorizing that certain RA-related pricing and contract information may be submitted by Community Choice Aggregators under seal and kept confidential.[28] CalCCA believes that pricing and contract information recently provided to the Energy Division could be used by the Commission in this proceeding to determine an administrative benchmark. In fact, given the pricing trends noted above, CalCCA believes that the more recent pricing information is likely to be more reflective of the value associated with RA from the Tree Mortality PPAs.

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[28] *See Administrative Law Judge's Ruling Granting The California Community Choice Association's Request to Submit Information Under Seal*, dated March 18, 2018 (R.17-09-020).

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Joint Application to Establish Non-Bypassable Charge ("NBC") for Above-Market Costs Associated with Tree Mortality Power Purchase Agreements ("Tree Mortality") in Compliance with Senate Bill 859 and Resolution E-4805.	Application No. 16-11-005 (Filed November 14, 2016)

CLOSING BRIEF OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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August 13, 2018

Counsel for the
California Community Choice Association

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Joint Application to Establish Non-Bypassable Charge ("NBC") for Above-Market Costs Associated with Tree Mortality Power Purchase Agreements ("Tree Mortality") in Compliance with Senate Bill 859 and Resolution E-4805.	)))))))	Application No. 16-11-005 (Filed November 14, 2016)

CLOSING BRIEF OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Pursuant to Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and in accordance with the *Scoping Memo and Ruling of Assigned Commissioner,* dated May 30, 2018 ("Scoping Memo"), as clarified in an email from assigned Administrative Law Judge ("ALJ") Doherty, dated July 23, 2018 ("Email Guidance"), the California Community Choice Association ("CalCCA") hereby submits this opening brief. References to exhibits are to exhibits served by CalCCA and the joint investor-owned utilities ("Joint IOUs"). In accordance with the Email Guidance, CalCCA is concurrently filing and serving a motion to enter CalCCA's previously served testimony into the evidentiary record.

I. INTRODUCTION AND SUMMARY

A. Description of CalCCA

CalCCA is a trade association representing operational Community Choice Aggregation ("CCA") programs in California. In addition to being an active participant in the Power Charge Indifference Adjustment ("PCIA") rulemaking proceeding (R.17-06-026), CalCCA has been an active participant in this proceeding. Among other things, CalCCA developed and submitted a presentation for the workshop held in this proceeding on December 12, 2017 ("CalCCA Presentation"). Also, in accordance with the *Administrative Law Judge's Ruling Entering*

Energy Division Staff Proposal Into The Record And Seeking Party Comments, dated April 17, 208 ("ALJ Ruling"), CalCCA submitted opening and reply comments on the Energy Division staff proposal, attached as Appendix A to the ALJ Ruling ("Staff Proposal"). CalCCA also served prepared testimony, dated June 28, 2018 (Exhibit ("Ex.") CalCCA-01), and rebuttal testimony, dated July 18, 2018 (Ex. CalCCA-02).

B. Description of the Tree Mortality NBC and PCIA Proceedings

This proceeding has been established "to establish a non-bypassable charge [("NBC")] for above-market costs associated with tree mortality power purchase agreements [("Tree Mortality NBC")] in compliance with Senate Bill [("SB")] 859 (Committee on Budget and Fiscal Review, 2016) and Commission Resolution E-4805."[1] In a separate proceeding, the Commission has committed significant resources to examine the PCIA, which has been the NBC used by the Commission to value most of the investor-owned utilities' ("IOUs") generation resources. As stated by the Assigned Commissioner in the PCIA proceeding, the Commission is engaged in an extensive examination "to review, revise, and consider alternatives to the [PCIA]."[2]

As noted in the PCIA Scoping Memo, "[t]he PCIA is a mechanism adopted by the Commission…to ensure that when electric customers of the IOUs depart from IOU service and receive their electricity from a non-IOU provider, those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[3] Included as a key

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1 Scoping Memo at 1-2.

2 *See Scoping Memo and Ruling of Assigned Commissioner*, dated September 25, 2017 (as modified on November 22, 2017), in R.17-06-026 ("PCIA Scoping Memo"), at 2.

3 PCIA Scoping Memo at 2.

part of the PCIA valuation methodology is the so-called "market price benchmark" ("MPB"), which consists of various elements that are generally intended to reflect the cost impact on the IOUs' resource portfolio associated with departing load.[4]

On August 1, 2018, the Commission issued the *Proposed Decision of ALJ Roscow* in the PCIA proceeding ("PCIA Proposed Decision"). The PCIA Proposed Decision spans well over one hundred pages, and reflects an extensive evidentiary and procedural record.[5] As summarized in the PCIA Proposed Decision, "[i]n [the PCIA Proposed Decision] the Commission adopts revised inputs to the market price benchmark that is used to calculate the [PCIA], the rate intended to equalize cost sharing between departing load and bundled load. The revised methodology will be used to calculate the PCIA that takes effect as of January 1, 2019."[6] The PCIA Proposed Decision "review[s] each of the three components that make up the MPB…."[7] With respect to so-called "brown" power (*i.e.*, underlying energy), the proposed methodology remains the same as the current PCIA methodology: "the Brown Power Index….shall be calculated and made available by the Commission's Energy Division as is currently done…."[8] The other two components of the MPB (the RPS and RA adders), which CalCCA has referenced and pointed to as part of this proceeding, will be changed.

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[4] *See* PCIA Scoping Memo at 8.

[5] *See* PCIA Proposed Decision at 10-12 (describing the procedural background leading to the PCIA Proposed Decision). During oral comments at the Commission's August 9 Business Meeting, Commissioner Peterman indicated that she would be issuing an alternate proposed decision. An alternate proposed decision would expand an already extensive examination of the PCIA.

[6] PCIA Proposed Decision at 3.

[7] PCIA Proposed Decision at 38 (referencing the so-called brown power, resource adequacy ("RA") capacity and renewables portfolio standard ("RPS") MPBs).

[8] PCIA Proposed Decision at 76.

The PCIA Proposed Decision adopts The Utility Reform Network's ("TURN") "approach for estimating the RPS Adder."[9] As described in the PCIA Proposed Decision, "[t]he RPS Adder shall be calculated using the reported prices of purchases and sales of renewable energy by the IOUs, CCAs and ESPs during the year two years prior to the forecast year ("year n-2") for delivery in the forecast year ('year n'). For example, the RPS Adder for 2020 would be calculated using data from 2018."[10] With respect to the RA adder, the PCIA Proposed decision "adopt[s] TURN's proposal for estimating the RA Adder, which shall be calculated using reported purchase and sales prices of IOU, [Community Choice Aggregators], and [Electric Service Provider ("ESP")] [(collectively, "Retail Sellers")] transactions made during (year n-1) for deliveries in (year n)."[11] In summary, under the PCIA Proposed Decision the RPS and RA adders will be based on actual, reported prices paid by Retail Sellers.

C. Summary of Positions and Recommendations

The following is a summary of CalCCA's principal positions and recommendations, as further described below:

- The Commission should use the MPB components from the PCIA Proceeding to determine the Tree Mortality NBC. As described below, this recommendation should not be construed as CalCCA's support for the MPB components in the PCIA Proposed Decision, since CalCCA is still actively litigating matters in the PCIA proceeding and has various concerns with the PCIA Proposed Decision. Rather, CalCCA's recommendation is based on its interest in consistent process and good practice.

- The Commission should use the RPS adder from the PCIA proceeding to determine the Renewable Energy Credit ("REC") value for the Tree Mortality NBC.

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9 PCIA Proposed Decision at 76.

10 PCIA Proposed Decision at 76 (internal footnote omitted).

11 PCIA Proposed Decision at 76 (internal footnote omitted).

- The Commission should use the RA adder from the PCIA proceeding to determine the capacity value for the Tree Mortality NBC.
- CalCCA does not object to the Joint IOUs' proposed use of the Public Purpose Program ("PPP") Charge to apply the Tree Mortality NBC.

II. ARGUMENTS

A. The Commission Should Use The Market Price Benchmark Components From The PCIA Proceeding To Determine The Tree Mortality NBC

In this proceeding, CalCCA has stated that the "PCIA valuation methodology should be used across all cost allocation processes, be they PCIA or policy-mandated procurement."[12] Moreover, CalCCA has stated that "[i]t is not efficient or appropriate for any party to duplicate cost allocation or resource valuation analysis efforts across two proceedings simultaneously."[13] CalCCA reaffirms these views, particularly in light of the recent issuance of the PCIA Proposed Decision. For efficiency, consistency and fairness, the PCIA valuation methodology should be used across all cost allocation processes, including the valuation methodology used to determine the Tree Mortality NBC. This recommendation, however, should not be taken as an endorsement for the outcomes set forth in the PCIA Proposed Decision. Indeed, CalCCA has various concerns with the PCIA Proposed Decision, and CalCCA will be expressing those concerns in due course as part of the PCIA proceeding. Rather, as stated previously, for efficiency, consistency and fairness, the PCIA valuation methodology should be used across all cost allocation processes.

The PCIA Proposed Decision was released on August 1, 2018, and the cover letter accompanying the PCIA Proposed Decision indicates that the PCIA Proposed Decision may be

[12] Ex. CalCCA-01 at 3 (citing CalCCA Presentation at 4).

[13] Ex. CalCCA-01 at 3-4 (citing CalCCA Presentation at 9).

heard at the Commission's September 13 Business Meeting.[14] As such, it is highly likely that a final proposed decision in the PCIA proceeding will be issued prior to or in the fourth quarter 2018, and that the revised MPB methodology will be employed for use as of January 1, 2019.[15] Given the procedural schedule set forth in this proceeding, it is unlikely that a final decision will be issued until the first quarter of 2019.[16] "Due to the complexity and number of issues in this proceeding," however, a final decision may not be issued until later in 2019.[17] Accordingly, components from the revised MPB methodology used for the PCIA can, as a practical matter, and should, as a policy matter, be used to determine the Tree Mortality NBC.

B. The Commission Should Use The RPS Adder From The PCIA Proceeding To Determine The Renewable Energy Credit Value For The Tree Mortality NBC

As described by the Joint IOUs, "under the IOU proposal, the estimated monetary value of the RECs [associated with the Tree Mortality PPAs], determined by a market index price for Portfolio Content Category 1 RECs or a $10/REC proxy value, would be netted against costs recovered from all benefiting customers."[18] The Joint IOUs further explain that "given the limited volumes associated with the [Tree Mortality] contracts and the lack of an approved REC allocation methodology, the Joint IOUs recommend

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14 As noted above, during oral comments at the Commission's August 9 Business Meeting, Commissioner Peterman indicated that she would be issuing an alternate proposed decision, but that the alternate proposed decision would be issued along a timeline that would allow for consideration of the alternate proposed decision at the Commission's September 13 Business Meeting.

15 *See* PCIA Proposed Decision at 3 ("The revised methodology will be used to calculate the PCIA that takes effect as of January 1, 2019.")

16 *See* Scoping Memo at 7. *See also* Rule 14.2 (issuance of recommended decision).

17 *See* Scoping Memo at 8.

18 Ex. Joint IOU-02 at 8-9.

relying on Platt's Daily to approximate market value or on the $10/MWh adopted in D.16-05-006, at p.23."[19]

CalCCA opposes the Joint IOUs' proposal. The value of RECs associated with the Tree Mortality PPAs should be based on the REC value set in the PCIA proceeding. Under the PCIA Proposed Decision, the value of RECs will be determined as follows: "The RPS Adder shall be calculated using the reported prices of purchases and sales of renewable energy by the IOUs, CCAs and ESPs during the year two years prior to the forecast year ("year n-2") for delivery in the forecast year ('year n'). For example, the RPS Adder for 2020 would be calculated using data from 2018."[20]

The approach taken in the PCIA Proposed Decision is similar to the approach examined by ALJ Doherty in this proceeding. On July 9, 2018, ALJ Doherty issued *Administrative Law Judge's Ruling Seeking Additional Information From Parties On Pricing Of Renewable Energy Credits* ("REC Price Ruling"). In the REC Price Ruling, ALJ Doherty directed the IOUs to serve "information on the prices for RECs established as part of the IOUs' 2018 solicitations for the sale of RPS-eligible generation and associated RECs.[21] ALJ Doherty issued the REC Price Ruling "[b]ecause this process results in a series of arms-length transactions for RECs that leads to the establishment of a price for those RECs, the prices for the RECs revealed by these ***transactions*** may be useful in constructing an administrative benchmark value for the

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[19] Ex. Joint IOU-02 at 11.

[20] PCIA Proposed Decision at 76 (internal footnote omitted). *See also* Appendix 1 of the PCIA Proposed Decision (describing the revised formula for the PCIA MPB).

[21] REC Price Ruling at 3 (referencing, among other things, information presented by Pacific Gas and Electric Company ("PG&E") in PG&E's Advice Letter 5294-E, filed on May 16, 2018.

RECs at issue in this proceeding."[22] The PCIA Proposed Decision arrives a similar conclusion, holding that "actual ***market transactions***" should be the basis for setting the MPB to reflect the value associated with REC attributes.[23] The Commission should likewise arrive at a similar conclusion in this proceeding, holding that actual market transactions are the most reliable, fair means of determining above-market costs.

C. The Commission Should Use The RA Adder From The PCIA Proceeding To Determine The Capacity Value For The Tree Mortality NBC

With respect to "capacity" or RA value, the Joint IOUs do not propose to monetize this value and net this monetized amount from overall costs to determine above-market costs associated with the Tree Mortality PPAs. Instead, the IOUs propose that "each retail seller would receive its proportional share of the RA credit arising from each of the [Tree Mortality PPAs]."[24] The IOUs justify this approach as follows: "As there is not an established RA market for capacity, in contrast to the established energy market, this proposal is fair and relatively easy to administer, as the Joint IOUs use this method for the [Cost Allocation Methodology ("CAM")]."[25] As described above, the Joint IOUs' proposal for determining RA value differs from the Joint IOUs' proposal for determining REC value, where the Joint IOUs propose to monetize the value. The Joint IOUs justify these differing approaches as follows: "The proposal for the IOUs to monetize and retain the value of the REC attributes rather than allocate them to benefiting [load-serving entities ("LSEs")] is the most administratively efficient solution to share the benefits of the renewable procurement, given the limited duration

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22 REC Price Ruling at 3 (emphasis added).

23 *See* PCIA Proposed Decision at 74 (referencing TURN's proposal) (emphasis added).

24 Ex. Joint IOU-02 at 8.

of the contracts (5-years) and small size of the procurement relative to the Joint IOUs total portfolio."[26]

CalCCA objects to the Joint IOUs' approach for determining the capacity or RA value from the Tree Mortality PPAs. Rather than direct distribution, the value of RA credits should be monetized and included in the cost-benefit calculation associated with the Tree Mortality NBC.[27] For purposes of monetizing the RA value associated with the Tree Mortality PPAs, the RA valuation methodology in the PCIA Proposed Decision should be used.

With respect to the RA adder, the PCIA Proposed decision "adopt[s] TURN's proposal for estimating the RA Adder, which shall be calculated using reported purchase and sales prices of [Retail Seller] transactions made during (year n-1) for deliveries in (year n)."[28] In this regard, the PCIA Proposed Decision relies on actual market transactions.[29]

1. There Is Little Or No Practical Way To Make Use Of RA Credits From The Tree Mortality PPAs

In order for the IOUs' RA valuation proposal to provide ***any*** benefit to CCAcustomers, the proposed transfer of RA credits to Community Choice Aggregators must occur in time to be used for compliance purposes by Community Choice Aggregators. RA credits are applied on a month-ahead and year-ahead basis.[30] As detailed by the Joint IOUs, the Tree Mortality PPAs

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25 Ex. Joint IOU-02 at 10.

26 Ex. Joint IOU-02 at 9; note 14.

27 *See* Ex. CalCCA-01 at 4 (citing CalCCA Presentation at 6).

28 PCIA Proposed Decision at 76 (internal footnote omitted).

29 *See* PCIA Proposed Decision at 74 (referencing TURN's reliance on transactions reflected in the Commission's Energy Division's RA Reports).

30 *See generally 2018 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings* (revised February 5, 2018) ("RA Guide") at 4-5. (A copy of the RA Guide is available at: www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454920 . By

began delivering energy as early as February 1, 2017 and as late as December 2, 2017.[31] As such, for the period from February 1, 2017 until the first compliance month in which the RA credits can be used by Community Choice Aggregators, RA credits from the Tree Mortality PPAs will have no value at all to Community Choice Aggregators (and CCA customers). As noted above, given the procedural schedule set forth in this proceeding, it is unlikely that a final decision will be issued until the first quarter of 2019, at the earliest.[32] Moreover, after the issuance of a final decision, certain implementation activities must also occur in order to transfer RA credits.[33] As such, for practical purposes, it is unlikely that the Joint IOUs would be able to transfer RA credits for ***year-ahead*** purposes until compliance-year 2020.[34] By this time, the Tree Mortality PPAs will ***not*** have a duration of five years, but in some cases will only have a remaining duration of slightly over two years.

The Joint IOUs rely "on the limited duration of the [Tree Mortality PPAs] (5-years)" as a basis for recommending monetization of REC value.[35] While this is persuasive with respect

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October 31, LSEs are required to make a year-ahead RA compliance showing, and 45 days prior to the compliance month, LSEs are required to make month-ahead RA compliance showing. (RA Guide at 4-5.)

31 *See* Exhibit Joint IOUs-02; Appendix A-1.

32 *See* notes 16 and 17, above.

33 For example, with respect to RA credits associated with CAM resources, the Commission's Energy Division must first determine each LSE's pro-rata share of CAM allocations for use in compliance filings, and must transmit this information via a letter to each LSE. Presumably this process or a similar one would be followed if the Commission were to adopt the IOUs' RA valuation proposal.

34 As noted above, in order to be useful for year-ahead purposes, the RA credits must be allocated and available for the October 31 compliance filing. (*See* note 30, above, referencing the RA Guide at 4.) As such, since a final decision in this proceeding is not expected to be implemented prior to October 31, 2018 (for compliance-year 2019), the first compliance year is 2020 that RA credits could be allocated and available.

35 *See* note 26, above (referencing Exhibit Joint IOU-02 at 9; note 14).

to contracts having a duration of five years, it is even more persuasive with respect to contracts having a remaining duration of two years. The Commission should consider the extremely limited remaining duration of the Tree Mortality PPAs when it determines how to value RA attributes. This consideration will, in CalCCA's view, lead to a conclusion that RA value should be determined by monetizing the RA attributes, not by transferring RA credits to Community Choice Aggregators. In any event, even if the Commission determines that RA credits should be transferred for the remaining duration of the Tree Mortality PPAs, an RA value must be determined ***by monetization*** during the period from February 1, 2017 through the first compliance period in which the RA credits have practical effect.

2. Actual RA Transaction Values Exist And Should Be Used For Purposes Of Setting The Tree Mortality NBC, With Due Consideration Of The Rising Cost Of RA

As described above, CalCCA believes that using the PCIA methodology for valuing RA under the Tree Mortality PPAs is the best approach. However, CalCCA is not opposed to using alternative means of identifying ***current*** RA prices for valuation and monetization purposes. Various sources of information on current RA prices are available. First, the final decision in this proceeding could order the Joint IOUs to provide current RA prices to the Energy Division. In this regard, the order would be similar to the REC Price Ruling. In the REC Price Ruling, ALJ Doherty directed the IOUs to serve "information on the prices for RECs established as part of the IOUs' 2018 solicitations for the sale of RPS-eligible generation and associated RECs.[36] CalCCA observes that the IOUs have similarly submitted various advice letters in 2018

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[36] REC Price Ruling at 3 (referencing, among other things, information presented by Pacific Gas and Electric Company ("PG&E") in PG&E's Advice Letter 5294-E, filed on May 16, 2018.

describing, under seal, information on RA prices that have resulted from "arms-length transactions" for RA. CalCCA notes that the following RA-related advice letters were filed in 2018 and that, similar to REC transactions, the prices for RA revealed by these transactions may be useful in constructing an administrative benchmark value for RA in this proceeding.

- On March 15, 2018, PG&E submitted Advice Letter 5252-E relating to RA cost responsibility associated with an RA transaction between PG&E and Silicon Valley Clean Energy Authority.[37]

- On April 16, 2018, PG&E submitted Advice Letter 5275-E relating to RA cost responsibility associated with an RA transaction between PG&E and King City Community Power.[38]

- On May 9, 2018, Southern California Edison Company ("SCE") submitted Advice Letter 3801-E relating to RA cost responsibility associated with an RA transaction between SCE and Desert Community Energy.[39]

Second, the Energy Division routinely collects pricing information on RA-related transactions. An aggregated summary of this pricing information is usually provided in so-called annual RA Reports.[40] On August 2, 2018, the Energy Division provided notice that the 2017 RA Report is available.[41] Prices for RA revealed in the 2017 RA Report may be useful in constructing an administrative benchmark value for RA in this proceeding. A cautionary note is appropriate, however. The Energy Division issued a paper earlier this year that describes various trends with respect to RA, some of which portends an increase in RA costs in 2018 and

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37 PG&E Advice Letter 5252-E was approved by the Energy Division on April 18, 2018, effective March 15, 2018.

38 PG&E Advice Letter 5275-E was approved by the Energy Division on May 14, 2018, effective April 16, 2018.

39 SCE Advice Letter 3801-E was approved by the Energy Division on June 14, 2018 in a non-standard disposition letter.

40 The annual RA Reports are available at http://cpuc.ca.gov/RA/.

41 The 2017 RA Report is available at http://www.cpuc.ca.gov/General.aspx?id=6307.

beyond.[42] The Energy Division Report describes the following trend with respect to RA, observing that deficiencies in RA are beginning to emerge:

> Prior to the 2018 year ahead RA process, LSEs had only ever filed two local waivers with CPUC. However, in September and October of 2017 several LSEs began contacting Energy Division staff regarding the inability to procure adequate local and system capacity. Of the twenty-seven LSEs that submitted year ahead 2018 RA filings on October 31, 2017, eleven filed waiver requests to cover local deficiencies totaling roughly 270 MW. In addition, the year ahead filings identified a collective deficiency of around 40 MW in system capacity.[43]

Presumably these deficiencies will result in increases to RA prices. As such, the Commission should exercise caution in taking RA-related pricing information in the 2017 RA Report and simply extrapolating that information.

Finally, CalCCA understands that Community Choice Aggregators recently provided pricing and contract information to the Energy Division in response to data requests from the Energy Division. (CalCCA understands that other LSEs also provided this information.) The distribution of this information under seal was facilitated by the issuance in R.17-09-020 of a ruling, dated May 18, 2018, authorizing that certain RA-related pricing and contract information may be submitted by Community Choice Aggregators under seal and kept confidential.[44] CalCCA believes that pricing and contract information recently provided to the Energy Division could be used by the Commission in this proceeding to determine an administrative benchmark. In fact, given the pricing trends noted above, CalCCA believes that

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42 *See* Energy Division staff report (*Current Trends in California's Resource Adequacy Program,* dated February 16, 2018) ("Energy Division Report"), available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457193.

43 Energy Division Report at 43.

44 *See Administrative Law Judge's Ruling Granting The California Community Choice Association's Request to Submit Information Under Seal*, dated March 18, 2018 (R.17-09-020).

the more recent pricing information is likely to be more reflective of the value associated with RA from the Tree Mortality PPAs.

D. CalCCA Does Not Object To The Joint IOUs' Proposed Use Of The PPP Charge To Apply The Tree Mortality NBC

As described by the Joint IOUs, "[t]he Joint IOUs propose[] that the [Tree Mortality] NBC be collected from all retail electricity customers in the IOUs' service areas through the PPP charge because this renewable energy program was developed for the express purpose of addressing a statewide public safety issue, and all Californians stand to benefit from the [Tree Mortality] procurement program."[45] According to the Joint IOUs, "the PPP [charge] provides an established, effective mechanism by which [the Tree Mortality PPA] costs should be recovered."[46]

CalCCA does not object to the IOUs' proposed use of the PPP charge to implement the Tree Mortality NBC. CalCCA generally believes that this approach is reasonable given that the financial amount at stake is not large enough to significantly change the PPP charge. In this regard, CalCCA understands that the incremental increase to the current PPP charge associated with the Tree Mortality NBC would be between 3 and 6 percent.[47] Other issues should be examined if additional or other generation-related charges are proposed for inclusion in the PPP charge.

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45 Ex. Joint IOUs-02 at 12.

46 Ex. Joint IOUs-02 at 12.

47 *See* Ex. CalCCA-01; Attachment 1 (incorporating discovery responses from the IOUs).

III. CONCLUSION

CalCCA thanks Commissioner Guzman-Aceves and Administrative Law Judge Doherty for their thoughtful consideration of this opening brief and the matters addressed herein.

Dated: August 13, 2018

Respectfully submitted,

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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 2019 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation (U 39 E)	Application 18-06-001 (Filed June 1, 2018)

PROTEST OF EAST BAY COMMUNITY ENERGY, MARIN CLEAN ENERGY, MONTEREY BAY COMMUNITY POWER, PENINSULA CLEAN ENERGY, PIONEER COMMUNITY ENERGY, AND SONOMA CLEAN POWER AUTHORITY TO APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY FOR 2019 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION

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July 5, 2018

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 2019 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation (U 39 E)	Application 18-06-001 (Filed June 1, 2018)

PROTEST OF EAST BAY COMMUNITY ENERGY, MARIN CLEAN ENERGY, MONTEREY BAY COMMUNITY POWER, PENINSULA CLEAN ENERGY, PIONEER COMMUNITY ENERGY, AND SONOMA CLEAN POWER AUTHORITY TO APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY FOR 2019 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION

I. INTRODUCTION

In accordance with Rule 2.6 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure ("Commission Rules"), East Bay Community Energy ("EBCE"), Marin Clean Energy ("MCE"), Monterey Bay Community Power ("MBCP"), Peninsula Clean Energy ("PCE"), Pioneer Community Energy ("Pioneer"), and Sonoma Clean Power Authority ("SCP") (collectively "the Joint CCAs")[1] submit the following protest to the *Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2019 Energy Resource Recovery Account and*

[1] The above-mentioned CCAs respectfully request independent party status as signatories to this protest.

Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation, filed on June 1, 2018 ("Application").[2] Pacific Gas and Electric Company's ("PG&E") Application would result in bundled rate decreases. However, they would result in an average increase in the Power Charge Indifference Adjustment ("PCIA") of about 10% and an average decrease in the generation rate of between 13-16%. While the reductions in overall rates are welcome, the increase in PCIA needs to be more closely examined, reviewed, and validated to ensure fair competition.

PG&E's Application currently does not provide sufficient evidence that its proposed rate changes are justified. PG&E has not sufficiently demonstrated that it adequately managed its portfolio to ensure that only unavoidable above-market costs are passed through to departing load customers via the PCIA.[3] State law only authorizes PG&E to pass on to CCA customers through the PCIA costs that are unavoidable.[4] Absent a transparent showing in this regard, the Joint CCAs are subject to a significant competitive disadvantage relative to PG&E, in violation of Senate Bill 790.[5] Moreover, lack of transparency and accountability renders the Joint CCAs' customers blind to cost shifts that are contrary to statute.[6] The Joint CCAs ask the Commission to carefully evaluate PG&E's proposed changes to the PCIA and the generation rate, and to establish metrics that will assist the Commission and interested stakeholders in assessing PG&E's portfolio management practices going forward.

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[2] PG&E's Application first appeared in the Daily Calendar on June 4, 2018. As such, this protest is timely pursuant to Rule 2.6(a) of the Commission's Rules.
[3] *See* Cal. Pub. Util. Code Section 366.2.
[4] See Cal. Pub. Util. Code Section 366.2(f)(2).
[5] *See* Section 2(h) of Senate Bill (SB) 790 (Leno, 2011).
[6] *See* Cal. Pub. Util. Code Section 366.3.

II. JOINT CCAs' INTEREST

Each of the Joint CCAs is governed by a Board of Directors comprised of elected officials that represent the individual cities and counties the CCA serves or an elected City Council.[7] CCAs must comply with the same mandates applicable to all load serving entities, including the Renewables Portfolio Standard ("RPS") requirements, Resource Adequacy requirements, and greenhouse gas emission reduction requirements.[8] CCAs also must meet local mandates to procure and maintain clean electricity portfolios that in many cases exceed state requirements for renewable generation. CCAs have and continue to meet this demand while offering affordable, competitive, and stable rates despite the historical increase and volatility of the PCIA. While CCAs agree that state law requires their customers to pay unavoidable above-market costs of commitments made on their behalf, CCAs are concerned that PG&E's proposed PCIA is not limited to the costs permitted by state law. CCAs are also concerned about the opaque process by which the PCIA is calculated and determined.

As advocates for their customers who will be subject to the PCIA, CCAs have a particular interest in the outcome of this proceeding. To the extent PG&E has not demonstrated that the costs included in the PCIA are unavoidable, the changes PG&E seeks are not in accordance with state law.

III. GROUNDS FOR PROTEST

PG&E has not sufficiently shown that the costs it seeks to include in the PCIA are limited to unavoidable costs. In particular, PG&E has not demonstrated that its portfolio management practices maximize the value of PG&E's portfolio and reduce above-market costs. The Joint

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[7] *See* Pub. Util. Code Section 366.2.
[8] *See* Cal. Pub. Util. Code Section 399.12(j)(2).

CCAs ask the Commission to address PG&E's portfolio management practices and undertake an evaluation beyond a limited review of PG&E's compliance with the "least-cost-best-fit" dispatch model. While bidding behavior is an important aspect of portfolio management, choosing which resources to keep online and which to retire or dispose of is more impactful. For example, PG&E's continued operation of the Diablo Canyon Power Plant ("Diablo Canyon") affects PCIA rates as proposed by PG&E, although continuing to operate Diablo Canyon is an avoidable cost. This plant is not needed for compliance with environmental policies, nor does it provide local or flexible capacity. Diablo Canyon's going forward costs exceed market prices, and the above market costs of operating Diablo Canyon are included in the PCIA as well as bundled generation rates. Because these costs could be avoided by ceasing to operate Diablo Canyon, or at least implementing season dispatch, they are not unavoidable and are hence improperly included in the PCIA. The role of the Commission is to address these types of questions to protect ratepayers.

While the general structure of the PCIA is the subject of Rulemaking 17-06-026, the propriety of PG&E's proposed increase in the 2019 PCIA is at issue in this proceeding. Therefore, the Joint CCAs seek to ensure that the revenue requirements PG&E proposes through the Energy Resource Recovery Account ("ERRA") process are fairly and transparently determined and weighed against the Commission's mandate by the California legislature "to facilitate the consideration, development, and implementation of community choice aggregation programs, to foster fair competition, and to protect against cross-subsidization by ratepayers."[9] To do so requires a comprehensive evaluation of PG&E's portfolio management practices.

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[9] *See* Section 2(h) of Senate Bill (SB) 790 (Leno, 2011).

To date the Commission has not afforded interested parties an adequate forum in which to examine PG&E's portfolio management practices. In PG&E's 2018 ERRA proceeding, Application ("A.") 17-06-005, the Commission's Scoping Memo and Ruling determined that "PG&E's administration of procurement contracts, as well as management of procurement portfolios are outside the scope of an ERRA forecast proceeding and best addressed in the compliance phase."[10] Yet, the Assigned Commissioner's Scoping Memo and Ruling in PG&E's most recent ERRA compliance proceeding (A.18-02-015) indicated that PG&E's contract management practices involved PG&E's bundled procurement plan.[11] As such, the Commission ruled that the ERRA compliance proceeding "was not the appropriate procedural venue to address changes to the bundled procurement plan" and that challenges to PG&E's contract management practices should be pursued via a Petition for Modification of the decision approving PG&E's bundled procurement plan.[12] The bundled procurement plans, however, are not portfolio management plans. The procurement plans only assess new resource *acquisition*, but do not evaluate acquired resource *disposition*. PG&E's resource management practices are squarely within the scope of this proceeding because PG&E's revenue request is based on how their portfolio performs in response to changing market and regulatory conditions.

In addition, the Commission should use this forecast proceeding to develop clear metrics beyond the traditional least-cost-dispatch model which focuses solely on resource operation. In fact, this focus ignores the least-cost best-fit metrics used to acquite many of these resources. These metrics can be referenced in PG&E's annual ERRA compliance proceeding to determine

[10] *Scoping Memo and Ruling of Assigned Commissioner*, Application 17-06-005, filed August 4, 2017 at 3.
[11] *Assigned Commissioner's Scoping Memo and Ruling*, Application 18-02-015, filed May 14, 2018 at 3-4.
[12] *Id*.

whether PG&E is in fact optimizing its portfolio adequately to minimize costs for all ratepayers.

These metrics could include:

- Forecasted revenue recovery outside of CAISO DA/RT/AS markets for UOG and PPA resources;
- Assessment of the opportunities for PPA sales against forecasted PPA costs and market prices;
- Assessment of PPA termination costs vs. continued acceptance of deliveries;
- Assessment of PPA curtailment savings vs. continued acceptance of deliveries at forecasted amounts; and
- Calculation and updating of the hedge value identified but not quantified in PG&E's RPS Procurement Plan to determine if the management of the portfolio optimizes that hedge value.

For the above-mentioned reasons, PG&E's Application should be closely scrutinized in this proceeding. The Commission should specifically focus on PG&E's portfolio management practices and how those practices may lead to increased costs for all ratepayers. This proceeding is an opportunity for the Commission to demonstrate leadership by proactively outlining how compliance with the CPUC's Procurement Policy Manual[13] should be demonstrated.

IV. RULE 2.6(d) COMPLIANCE

A. Proposed Category

PG&E appropriately categorizes the instant proceeding as "ratesetting."

B. Need for Hearing

Due to the significant anti-competitive impacts on CCAs that may result from the approval of PG&E's requested revenue requirement and contract management practices,

[13] California Public Utilities Commission AB 57, AB 380, SB 1078 Procurement Policy Manual. Available online at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10906

evidentiary hearings will be necessary. The factual record will need to be explored in detail to determine whether PG&E's proposed revenue requirements are accurate, reasonable, and represent only the unavoidable above-market costs of PG&E's portfolio.

C. Proposed Schedule

The Joint CCAs do not propose any revisions to the schedule as proposed by PG&E.

V. SERVICE LIST

Filings and other communications to this proceeding should be served on the following individuals:

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IV. <u>CONCLUSION</u>

The Joint CCAs thank Commissioner Guzman Aceves and Assigned Administrative Law Judge Eric Wildgrube for their thoughtful consideration of this protest and the issues detailed herein.

Respectfully submitted,

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July 5, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Joint Application to Establish Non-Bypassable Charge ("NBC") for Above-Market Costs Associated with Tree Mortality Power Purchase Agreements ("Tree Mortality") in Compliance with Senate Bill 859 and Resolution E-4805.	Application No. 16-11-005 (Filed November 14, 2016)

REPLY BRIEF OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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

Joint Application to Establish Non-Bypassable Charge ("NBC") for Above-Market Costs Associated with Tree Mortality Power Purchase Agreements ("Tree Mortality") in Compliance with Senate Bill 859 and Resolution E-4805.	)))))))	Application No. 16-11-005 (Filed November 14, 2016)

**REPLY BRIEF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

Pursuant to Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and in accordance with the *Scoping Memo and Ruling of Assigned Commissioner,* dated May 30, 2018 ("Scoping Memo"), as clarified in an email from assigned Administrative Law Judge ("ALJ") Doherty, dated July 23, 2018, the California Community Choice Association ("CalCCA") hereby submits this reply brief. References to exhibits are to exhibits served by CalCCA and the joint investor-owned utilities ("Joint IOUs").

I. REPLY

A. The Joint IOUs' Claim That They Have Proposed And That The Commission Has Already Approved A Resource Adequacy Value Is False

As summarized by CalCCA in its closing brief, this proceeding has been established "to establish a non-bypassable charge [("NBC")] for above-market costs associated with tree mortality power purchase agreements [("Tree Mortality NBC")] in compliance with Senate Bill [("SB")] 859 (Committee on Budget and Fiscal Review, 2016) and Commission Resolution E-4805."[1] In proposing a Tree Mortality NBC, the Joint IOUs have proffered an incomplete construct with respect to valuing resource adequacy ("RA") from the tree mortality power purchase agreements ("Tree Mortality PPAs"). The Joint IOUs propose that, ***after*** the Commission approves the Tree Mortality NBC, "each retail seller would receive its proportional share of the RA credit arising from each of the [Tree Mortality PPAs]."[2] However, with respect to the time period ***prior to*** Commission approval of the Tree Mortality NBC, the Joint IOUs have been silent in this proceeding, aside from the Joint IOUs' unavailing late-attempt in their closing brief to rectify the evidentiary void.

CalCCA identified the incomplete nature of and problem with the Joint IOUs' evidentiary showing in CalCCA's rebuttal testimony and in CalCCA's closing brief.[3] Based on CalCCA's rebuttal testimony, the Office of Ratepayer Advocates ("ORA") agreed that a problem exists with respect to the Joint IOUs' evidentiary showing:

> The Joint IOUs' proposal to allocate RA capacity credit produced by the Tree Mortality PPAs among load serving entities by share of coincident peak is problematic because certain BioRAM contracts have already been deployed. CalCCA raises an important concern that for the period from February 1, 2017 through the first RA compliance month in which the RA credits can be used by CCAs, RA credits from Tree Mortality PPAs have no value since RA credits are applied on a month-ahead and year-ahead basis. Further, "it is unlikely that the IOUs would be able to transfer RA credits for year-ahead purposes until compliance-year 2020." Given RA accounting rules, the Joint IOUs' proposal to allocate RA credit to CCAs and ESPs is not workable for contract years 2017 through 2019. The Commission should not adopt the Joint IOUs' proposal to allocate RA credit for years in which such credit would not be useful.[4]

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1 CalCCA Closing Brief at 2 (citing Scoping Memo at 1-2).

2 Exhibit ("Ex.") Joint IOU-02 at 8.

3 *See* [citation to rebuttal testimony and closing brief].

4 ORA Closing Brief at 5 (internal citations omitted). CalCCA understands that, pursuant to Senate Bill ("SB") 854 (2018), ORA has been renamed the Public Advocates Office of the California Public Utilities Commission. However, for purposes of this reply brief, CalCCA will use ORA as the name that was used on ORA's closing brief.

In their closing brief, the Joint IOUs unreservedly state that CalCCA's and ORA's concerns are moot, since "each of the Joint IOUs has ***proposed***, and received ***Commission approval***, to establish interim mechanisms to monetize and credit the value received for expiring RA credits…."[5] The Joint IOUs underscore this point in a subsequent pleading in this proceeding, as follows: "There is no need for the Commission to take further evidence on the interim RA value because tariff language in each IOU's preliminary statement associated with each IOU's Advice Letter is ***already effective***."[6] The "advice letters" to which the Joint IOUs refer are the advice letters by which the Joint IOUs established ***memorandum accounts*** for the purpose of "track[ing] and record[ing] procurement cost ordered by Resolution E-4770."[7]

In the Joint IOUs' advice letters, the Joint IOUs expressly state that "[d]isposition of the memorandum account balances shall be determined in the final decision issued in the associated Tree Mortality Nonbypassable Charge Application…."[8] However, in their closing brief the Joint IOUs would have the Commission and parties believe that this issue is no longer a live issue in this proceeding, since the Joint IOUs' advice letters were "made effective,"

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5 Joint IOUs Closing Brief at 11 (emphasis added).

6 *See Joint IOUs' Response To Motion Of Office Of Ratepayer Advocates To Set Aside Submission Of The Record*, dated August 24, 2018 ("Joint IOU Response") at 2 (emphasis added).

7 *See, e.g.,* PG&E Advice Letter ("AL") 4954-E; BioRAM Memorandum Account (Sheet 1). *See also* Joint IOUs Closing Brief at 4 ("Resolution E-4805 also required the Joint IOUs to file Tier 2 advice letters within 30 days of its issuance creating memorandum accounts to track the costs of procurement associated with the tree mortality emergency while the application on cost allocation is pending.").

8 *See, e.g.,* PG&E AL 4954-E-A at 2.

having "received Commission approval," and therefore there is "no need for the Commission to take further evidence" on this matter.[9]

The Joint IOUs' statements about the effect to be given the Joint IOUs' advice letters are false. In ***this proceeding***, the Commission can and must determine the RA value from the Tree Mortality PPAs. There is nothing in the Joint IOUs' memorandum account advice letters, or the Energy Division's disposition letter, that precludes consideration of this issue in this proceeding, or predetermines an outcome.

1. This Proceeding, Not An Advice Letter Process, Is The Venue For Determining How RA From The Tree Mortality PPAs Should Be Valued

The Scoping Memo provides clear guidance on what issues will be considered in this proceeding and what evidence is necessary from the Joint IOUs to support the Joint IOUs' proposals. Included as an issue within the scope of this proceeding is an examination of "[t]he valuation and calculation methodologies for the proposed NBC."[10] The Scoping Memo defines what evidence is necessary from the Joint IOUs in this proceeding to support valuation of RA from the Tree Mortality PPAs: "[The Joint IOUs] must also provide information on the actual… capacity… values created by these contracts and how they are being apportioned to their bundled ratepayers."[11] Importantly, nowhere in the Scoping Memo is there an exclusion from this evidentiary standard for RA values for the period of time that the Joint IOUs now

9 *See* notes 5 and 6, above.

10 Scoping Memo at 2.

11 Scoping Memo at 3 (in reference to RA value). *See also* Scoping Memo at 3-4 ("[T]estimony from the utilities must characterize every element of the asserted costs and benefits of the NBC, why it is a cost, why it is a benefit, to whom it is a cost and benefit, how the allocation methodology for the costs and benefits is derived, and how the NBC nets these costs and benefits.").

define as "interim" (*i.e.*, the period of time prior to Commission approval of the Tree Mortality NBC).[12] Rather, the Scoping Memo makes clear that Joint IOUs must, ***in this proceeding***, provide testimony on RA values created by the Tree Mortality PPAs for the full duration of the contracts.[13]

The Commission's General Order ("GO") 96-B describes the advice letter process. General Rule 5.1 states that "The advice letter process provides a quick and simplified review of the types of utility requests that are expected neither to be controversial nor to raise important policy questions." General Rule 5.2 further clarifies that an IOU must file an application where an IOU "seeks Commission approval of a proposed action that the utility has not been authorized, by statute, by this General Order, or by other Commission order, to seek by advice letter." As the Joint IOUs acknowledge in their memorandum account advice letters, recovery of procurement costs under the Tree Mortality PPAs will be a two-step process: First, the Joint IOUs will "track and record" procurement costs associated with the Tree Mortality PPAs ***through memorandum accounts***.[14] Second, the Joint IOUs will seek cost-recovery of the associated memorandum account costs ***in this proceeding***.[15]

This two-step process is consistent with how the Commission has defined memorandum accounts in other contexts:

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12 *See, e.g.,* Joint IOUs Closing Brief at 12 (Referencing PG&E AL 5354-E at 2).

13 *See* notes 10 and 11, above.

14 *See, e.g.,* PG&E AL 5354-E-A at 1 ("On October 21, 2016, the Commission issued Resolution E-4805… requiring the [IOUs] to track electric procurement costs associated with power purchase agreements executed to comply with Resolution E-4770 and [Resolution E-4805].").

> A memo account is an accounting device that, after approval by the Commission or upon statutory notice, may be used by a utility to record various expenses it incurs. The utility ***may later seek authorization*** from the Commission to recover the recorded amounts by passing them on to consumers in rates. The establishment of a memo account does not guarantee that the utility will recoup the tracked amount, but a utility is precluded from recovering amounts not booked to a memo account. Memo accounts ***allow the Commission to consider*** recovery of utility expenses that have occurred in the past without incurring retroactive ratemaking.[16]

In light of this background, it is incredulous for the Joint IOUs to claim or imply in their closing brief that the Energy Division's approval of memorandum accounts should be viewed as approving how RA capacity from the Tree Mortality PPAs should be valued and apportioned to bundled customers. That is precisely the purpose of this proceeding, not the IOUs' advice letter process.

2. The Joint IOUs' Description In Their Advice Letters Is No Substitute For Evidence In This Proceeding

In their closing brief, the Joint IOUs object to the fact that "CalCCA states that the IOUs have advanced no valuation methodology that would accomplish [interim period RA] monetization."[17] CalCCA stands behind its assertion. ***In this proceeding***, the Joint IOUs have offered no evidence whatsoever for how the Joint IOUs would monetize RA value in the interim period.

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15 *See, e.g.,* PG&E AL 5354-E-A at 2 ("Disposition of the memorandum account balances shall be determined in the final decision issued in the associated Tree Mortality Nonbypassable Charge Application.").

16 Division of Water and Audits, *Standard Practice for Processing Rate Offsets and Establishing and Amortizing Memorandum Accounts* (Standard Practice U-27-W), dated April 16, 2014, at 3 (emphasis added). A copy of Standard Practice U-27-W may be found at the following website: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M090/K002/90002198.PDF.

17 Joint IOUs Closing Brief at 11 (citing Ex. CalCCA-02 at 2).

It is a clear legal precept in Commission proceedings that the IOU applicant carries the burden of proof and must meet this burden of proof with a substantial affirmative showing.[18] Notwithstanding this legal precept and the clear guidance provided in the Scoping Memo on the need for the Joint IOUs to provide "testimony" in this proceeding on monetizing RA value in the interim period, the Joint IOUs have failed to meet their burden of proof. Their closing brief acknowledges this fact. Noticeably absent from the Joint IOUs' closing brief is any reference whatsoever to ***testimony*** describing the Joint IOUs' proposal for monetizing RA value during the interim period. Instead of properly acknowledging this flaw, as ORA does,[19] the Joint IOUs make an unavailing late attempt in their closing brief to bootstrap general, descriptive information in the Joint IOUs' advice letters and imbue this information with qualities and characteristics associated with ***testimony***. The Commission should disregard these attempts to substitute advice letter information for actual testimony in this proceeding.

3. Information Provided In The Joint IOUs' Closing Brief Is Patently Insufficient To Satisfy The Joint IOUs' Burden Under The Scoping Memo And General Standards

As noted above, the Scoping Memo requires the Joint IOUs to provide "specific information" through "testimony" – testimony that is exacting and discrete. In this regard, the Scoping Memo states as follows: "***In testimony***, the utilities must clarify ***each*** element of the NBC so that parties may understand why it is a ***discrete element*** and determine how the various

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18 *See, e.g.,* D.06-05-016 at 7 (emphasis added) ("As the applicant, [the utility] must meet the burden of proving that it is entitled to the relief it is seeking in this proceeding. [The utility] has the burden of affirmatively establishing the reasonableness of ***all aspects*** of its application. Intervenors."). *See also* D.924964 (CPUC 2d 693, 701) (emphasis added) ("Of course the burden of proof is on the utility applicant to establish the reasonableness of energy expenses sought to be recovered…We expect ***a substantial affirmative showing*** by each utility with percipient witnesses in support of ***all elements*** of its application….").

elements can be reconstructed to reflect the contract actually signed by the utilities. This means that testimony from the utilities ***must characterize every element*** of the asserted costs and ***benefits*** of the NBC, why it is a cost, why it is a benefit, to whom it is a cost and benefit, how the allocation methodology for the costs and benefits is derived, and how the NBC nets these costs and benefits."[20]

The Joint IOUs have failed to provide testimony that comes anywhere close to meeting the standard set in the Scoping Memo. Instead, recognizing this flaw, the Joint IOUs attempt to rehabilitate their deficient showing by using their closing brief to provide information. The Commission should reject this procedurally improper attempt for several reasons.

First, the information provided in the Joint IOUs' closing brief is not "testimony" for which the Joint IOUs are subject to procedural requirements. It is unfair and prejudicial for the Joint IOUs to introduce facts in their closing brief for which parties have not been given an opportunity to test through discovery, potentially cross-examine or rebut.

Second, the information provided in the Joint IOUs' closing brief is not "specific," as required by the Scoping Memo. The Joint IOUs devote extensive verbiage in their closing brief to describe the ***process and operation*** associated with the Joint IOUs' memorandum accounts, but nowhere do the Joint IOUs provide specific, discrete information about the actual RA value derived in the interim period. For PG&E and SCE, no information is

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[19] *See* ORA Closing Brief at 5.

[20] Scoping Memo at 3-4 (emphasis added).

provided on what price has been used for RA valuation purposes.[21] Certainly, the confidentiality of such information should not be at issue, since the Joint IOUs could have provided this information under seal. The plain fact is that the Joint IOUs have failed to provide specific information in this proceeding on RA valuation during the interim period. Accordingly, there is no Joint IOU proposal for the Commission to entertain. That said, CalCCA generally agrees with a recent ruling by the ALJ that there is a sufficient evidentiary record for the Commission to make a determination.[22] To reiterate, however, with respect to the interim period, the evidentiary record is devoid of evidence ***from the Joint IOUs***. For its part, CalCCA has provided extensive evidence on RA monetization values, both for the interim period and beyond.[23] Therefore, CalCCA has met its burden; the Joint IOUs have not.[24]

Third, the information provided in the Joint IOUs' closing brief does not reflect a joint or common proposal among the Joint IOUs. Indeed, based on the limited information provided by the Joint IOUs in their closing brief, it appears that the Joint IOUs' respective proposals are ***vastly*** different. For example, as noted above, SDG&E appears to use publicly available data that always produces an ***above-zero*** value, whereas PG&E uses an approach that

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21 For SDG&E, specific information on RA valuation can be derived, since SDG&E uses publicly available data in the Commission's annual RA report. *See* Joint IOUs Closing Brief at 15 ("SDG&E will value RA based on the CPUC's annual RA report for the relevant month while cost allocation is pending (the interim period).").

22 *See ALJ Email Ruling*, dated August 27, 2018.

23 *See* CalCCA Closing Brief at 8-14 (summarizing an extensive record for RA monetization values, including references to Ex. CalCCA-01 at 4, the Joint IOUs' advice letters on RA sales to Community Choice Aggregators and the 2016 and 2017 Annual RA Reports).

24 *See, e.g.,* D.87-12-067 (27 CPUC2d 1, 22) (describing the burden of an intervenor to present evidence explaining its position and raising reasonable doubts about the IOU's countervailing position).

regularly produces a value of ***zero*** for RA from the Tree Mortality PPAs.[25] To be clear, ascribing a value of zero to RA from the Tree Mortality PPAs, as apparently proposed by PG&E, is patently unreasonable.

B. The Joint IOUs' Late Proposal To Accommodate An "Indefinite" or Open-Ended Duration To Tree Mortality PPAs Under Senate Bill 859 Should Be Denied

In their closing brief, the Joint IOUs propose for the first time that the duration of Tree Mortality PPAs and associated cost-recovery should not be circumscribed by SB 859. Until their closing brief, the Joint IOUs had adhered to a position that limited the duration of Tree Mortality PPAs to their underlying authorizing source. For example, the Joint IOUs rightly observed that SB 859, as reflected in Resolution E-4805, statutorily limited the term of Tree Mortality PPAs to "5-year contractual commitments."[26] The Joint IOUs also rightly observed that Tree Mortality PPAs under Resolution E-4770-reflect "5-year contractual commitments which the Joint IOUs would have the right to extend for one year at a time, up to a cumulative total of 10 years."[27]

In their closing brief, however, the Joint IOUs introduce for the first time the possibility that the Joint IOUs could seek an "extension" of Tree Mortality PPAs ***under SB 859***. The Joint IOUs' language in this regard is subtle, and problematically vague and open-ended. With

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25 *See, e.g.,* Joint IOUs Closing Brief at 15 (citing PG&E AL 5354-E-A; emphasis added) ("PG&E proposes to sell, ***if possible***, a portion of the RA capacity and record (credit) the proceeds of the sale to the BioMASS and BioRAM memorandum accounts as an offset to the costs."). CalCCA understands that much of RA capacity has gone unsold, and therefore has been assigned zero value by PG&E.

26 *See* Ex. Joint IOU-02 at 2:11.

27 Ex. Joint IOU-02 at 3:2-3 (referencing Resolution E-4770 at 1). (The correct page reference is to page 11 of Resolution E-4770.)

respect to Tree Mortality PPAs associated with SB 859, the Joint IOUs state that "[a] sunset date for cost recovery may not coincide with the expiration of the Tree Mortality Procurement…***due to a subsequent extension*** of the contract approved by the Commission."[28] The Joint IOUs provide no description of what event could give rise to an "extension." An extension due to a change of law, on the one hand, is vastly different than an extension proposed by the Joint IOUs and approved by the Commission, on the other hand. In light of the Joint IOUs' subtly vague proposal in their closing brief, the Commission should expressly clarify that cost-recovery through the Tree Mortality NBC for SB 859-related contracts is circumscribed by statute. Stated differently, cost-recovery for an ***extension*** of a Tree Mortality PPA authorized under SB 859 should only be applied to Community Choice Aggregation ("CCA") customers if expressly authorized by the Legislature.

The importance of this clarification should not be overlooked. The Legislature has repeatedly stated that Community Choice Aggregators should handle all generation-related activities for CCA customers, excepting only those unique arrangements whereby the Legislature expressly authorizes procurement by the IOUs.[29] This statutory directive, which envisages meaningful self-procurement options for Community Choice Aggregators, is consistent with other statutory provisions.[30] Self-procurement is central to the mission of

28 Joint IOUs Closing Brief at 19 (emphasis added).

29 *See, e.g., Protest of the California Community Choice Association*, dated January 6, 2017 ("CalCCA Protest"), at 2 (citing Public Utilities Code Section 366.2(a)(5), as follows: "[Community Choice Aggregators] 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.").

30 *See* CalCCA Protest at 2 (citing Public Utilities Code Section 380(a)(5) [defining the following as a legislative objective with respect to the resource adequacy program: "[m]aximize the ability of community choice aggregators to determine the generation resources

Community Choice Aggregators. This is perhaps uniquely true with respect to Tree Mortality PPAs, where either the generating resource or the feedstock is located within the service area of Community Choice Aggregators.[31] Accordingly, absent express statutory authority, even in exigent circumstances, the Commission should not authorize the IOUs (directly or implicitly) to extend Tree Mortality PPAs for CCA customers.

C. The Joint IOUs' Views Regarding Rulemaking 17-06-026 Should Be Given Little Weight

After rightly acknowledging that the Scoping Memo identifies the need to coordinate with Rulemaking ("R.")17-06-026 (the Power Charge Indifference Adjustment ("PCIA") proceeding), the Joint IOUs conclude that "the PCIA – in either its existing or future forms – is neither dispositive ***nor relevant*** to the development of the [Tree Mortality NBC]."[32] The Joint IOUs come to this summary conclusion after expressing their view that "[t]he broad allocation of costs and benefits [associated with the Tree Mortality NBC] is more closely analogous to [Cost Allocation Mechanism ("CAM")], which similarly applies to all benefitting customers, than to the PCIA, which is meant to (but does not currently) ensure bundled customer indifference to the decision of current bundled customers to seek future service from a non-IOU retail seller."[33] The Joint IOUs' subjective assertions should be accorded little weight.

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used to serve their customers."] and Section 454.51(d) [expressly providing a self-procurement option for Community Choice Aggregators with respect to renewable integration requirements]).

31 For example, one of the six generation resources associated with the Tree Mortality PPAs is located in a Community Choice Aggregator's service area (Pioneer Community Energy), and other Community Choice Aggregators operate in areas designated high-hazard zones.

32 Joint IOUs Closing Brief at 21 (emphasis added).

33 Joint IOUs Closing Brief at 21 (internal citations omitted).

The Joint IOUs state that the Tree Mortality NBC issue is more suited for CAM treatment than for PCIA treatment.[34] However, the CAM approach is only supposed to be available to resources needed for grid ***reliability***.[35] This finding has not been made with regard to the resources associated with the Tree Mortality PPAs. As such, the Joint IOUs' proposed use of the CAM methodology is at odds with the CAM methodology's statutorily-specified conditions. This proceeding is not for the purpose of allocating grid-reliability costs and benefits. This is a significantly different focus from the need to address ***above-market*** costs of the Tree Mortality PPAs, for which a PCIA approach is better-suited.

The principal reason to look to, rely on and coordinate with the PCIA proceeding is the significant focus in that proceeding on establishing a proper "market price benchmark." As denoted by title of this proceeding, and as reflected in the Scoping Memo, the purpose of this proceeding is to determine "***above-market*** costs associated with tree mortality power purchase agreements in compliance with Senate Bill (SB) 859…."[36] It is impossible to determine "above-market" costs without relying on a "market price benchmark." As such, a market price benchmark, in one form or another, will be necessary in this proceeding. It is undeniable that the PCIA proceeding has devoted significant attention to the important work of determining a market price benchmark.[37]

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34 *See* note 33, above.

35 *See, e.g.,* D.11-05-005 at 7 (describing CAM "statutorily-specified" conditions relating to generation resources "needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory."). D.11-05-005 implemented that CAM-related provisions set forth in SB 695 (2009).

36 *See* Scoping Memo at 2 (emphasis added).

37 *See generally Proposed Decision of ALJ Roscow* (in R.17-06-026), dated August 1, 2018 ("PCIA Proposed Decision"), at 10-12 (Section 1.1 - Procedural Background).

As CalCCA has repeatedly stated and justified, reliance on the significant efforts being undertaken in the PCIA proceeding with respect to the market price benchmark is both efficient and reasonable.[38] That said, CalCCA reiterates what it said in its opening brief, namely, CalCCA's continuing recommendation to rely on the market price benchmark in the PCIA proceeding should not be taken as an endorsement for the outcomes set forth in the PCIA Proposed Decision (or now also, the *Alternate Proposed Decision of Commissioner Peterman* (August 14, 2018)). CalCCA is continuing to address its concerns with the market price benchmark in the PCIA proceeding. CalCCA nevertheless continues to believe that efficiency, consistency and fairness demand that the PCIA market price benchmark (and its associated valuation methodologies) should be used across all cost allocation processes.

CalCCA offers a final observation. The Joint IOUs' preference for the CAM is undeniably derived from the CAM's allocation of RA credits, not the CAM's establishment of an appropriate above-market cost methodology. This type of outcome-oriented advocacy should be weighed accordingly. If the outcome of this proceeding were to allocate attributes from the Tree Mortality PPAs, then the CAM approach might have merit. However, if, as noted in the title of this proceeding and the Scoping Memo's description, the outcome of this proceeding is to determine above-market costs and allocate those costs on a nonbypassable basis, then the PCIA proceeding is relevant and informative.

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38 *See, e.g.,* CalCCA Closing Brief at 5 (summarizing CalCCA's position).

II. CONCLUSION

CalCCA thanks Commissioner Guzman-Aceves and ALJ Doherty for their thoughtful consideration of this reply brief and the matters addressed herein.

Dated: August 31, 2018

Respectfully submitted,

/s/ Scott Blaising

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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 2019 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation. (U39E)	Application 18-06-001 (Filed June 1, 2018)

OPENING BRIEF OF EAST BAY COMMUNITY ENERGY, MARIN CLEAN ENERGY, MONTEREY BAY COMMUNITY POWER, PENINSULA CLEAN ENERGY, PIONEER COMMUNITY ENERGY, SILICON VALLEY CLEAN ENERGY AND SONOMA CLEAN POWER

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East Bay Community Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, Silicon Valley Clean Energy, and Sonoma Clean Power, collectively the Joint Community Choice Aggregators ("CCAs"), submit this Opening Brief in opposition to Pacific Gas & Electric Company's ("PG&E's") Energy Resource Recovery Account ("ERRA") application, filed June 1, 2018 ("Application").[1] The Joint CCAs operate community choice aggregation programs in PG&E's service territory, collectively supplying electricity to over 1.6 million residential, commercial and industrial accounts, rising to over 2 million in the next year.[2]

I. Introduction and Summary

PG&E's Application requests a substantial increase in the Power Charge Indifference Adjustment ("PCIA") CCA customers must pay. The increase would result in a PCIA revenue

[1] A.18-06-001, *Application of Pacific Gas and Electric Company (U 39 E) for 2019 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation* (June 1, 2018) ("Application").
[2] Exh. Joint CCAs-1, 1:6-9.

requirement of $1.068 billion,[3] an amount $436 million higher than the previous year, equaling a 63% escalation,[4] and translating to a 3.1% expansion in rates for residential CCA customers and an average 2% rise in rates for all CCA customers.[5] The rate hike will have a substantial impact on both CCA customers and the level of PG&E's rates compared to those of CCAs. A pending final decision in the PCIA Rulemaking ("R.") 17-06-026 likely will compound the increase.

Part of the increase derives from an impermissible revision to the indifference calculation that allocates revenues from PG&E's sale of Resource Adequacy ("RA") capacity and Renewable Portfolio Standard ("RPS") generation to other load-serving entities ("LSEs") for the first time. The utility neither expressly acknowledges nor clearly explains this deviation from the long-established indifference methodology in either its application or prepared testimony, but rather buries the proposal within its tables and work papers. PG&E's unprecedented approach – which uses a new methodology inconsistent with Commission direction – results in unlawful and unreasonable rates. As such, the utility has failed to meet its burden of proof on three of the seven issues identified in the Scoping Ruling to this proceeding:

Issue 1. PG&E's requested 2019 ERRA Forecast PCIA of $1.068 billion is unreasonable and should not be adopted.[6]

Issue 5. The calculations and entries underlying the proposed PCIA rates are not in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes.[7]

Issue 6. PG&E's rate proposals associated with its proposed total electric procurement revenue requirements to be effective in rates on January 1, 2019 should not be approved.[8]

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[3] Application at 2.
[4] Exh. PG&E-1, 9-12:5-6 and Table 9-1.
[5] Application at Exhibit A – Table 1, line 18.
[6] A.18-06-001, *Assigned Commissioner's Scoping Memo and Ruling*, p. 2 (Aug. 16, 2018).
[7] *Id.* at 3.
[8] *Id*.

In contrast to PG&E's approach, the Joint CCAs' proposed treatment for RA and RPS revenues adheres to the Commission's prior direction on sales revenues and addresses the shortcomings in PG&E's application in a lawful manner. If the Commission does not adopt the Joint CCAs' approach, PG&E should be required to track its sales revenues in a balancing account until the Commission establishes an appropriate forecasting method in a proceeding to which all investor-owned utilities ("IOUs") and other LSEs are provided notice. Such an approach will ensure any under- or over-collections can be recovered based on the methodology later adopted by the Commission.

Two other important issues require Commission decision-making in this proceeding, or clear Commission guidance on where they should be addressed, prior to any finding that PG&E has met its burden. The first is a misallocation of costs related to PG&E's largest utility-owned generation ("UOG") resource, the Diablo Canyon Power Plant ("DCPP" or "Diablo Canyon"). The misallocation results in DCPP being bid into the market below its going-forward costs. Correcting the misallocation requires adoption of the Joint CCAs' proposals in this proceeding on an interim basis, resolution of the issue in the PCIA docket, or a clear indication regarding where the issue should be taken up if it is not fully addressed by either of the first two options.

Finally, persistent procedural and transparency issues within PG&E's ERRA forecast proceedings continue to hamper CCAs' ability to understand, plan for, and protect their customers from potentially severe, short-term rate impacts. The mechanics of PG&E's ERRA forecast proceeding are currently outside the scope of the PCIA docket, and the Joint CCAs seek the Commission's guidance on where these critical issues should be raised and resolved.

In reforming the PCIA, the Commission first initiated a working group process to set the foundation for potential petitions to modify or petitions for rulemaking. The Joint CCAs suggest a similar approach here to address these critical and persistent issues.

II. Legal Standard and the Commission's Policymaking Prohibition in ERRA Applications.

The magnitude of the impact of PG&E's application on both departed and bundled customers requires cautious and careful consideration under the applicable standards of proof. PG&E, as the applicant, has the burden of affirmatively establishing the reasonableness of all aspects of its application,[9] and that burden of proof generally is measured based upon a preponderance of the evidence.[10]

The purpose of ERRA forecasting dockets is "to assure timely recovery of the utilities' actual electric procurement costs, as required by Public Utilities Code (Pub. Util. Code) Section 454.5(d)(3)."[11] The Commission has repeatedly made clear that it is unwilling to consider any policy changes in ERRA forecasting dockets. The Commission's last ERRA forecasting decision expressly found that policy issues and other industry-wide practices such as changes to the PCIA methodology are properly addressed in rulemaking dockets, such as R.17-06-026.[12] Instead of addressing broader policy or rule changes, the scope of ERRA forecasting proceedings is limited to evaluating the IOUs' compliance with prior Commission orders, rules or policies.[13] For example, the Scoping Memo in A.17-06-005 rejected certain issues raised by CCA parties in their Protest to PG&E's 2018 ERRA forecasting application, stating:

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[9] D.12-12-030 at 42.
[10] *See, e.g.,* D.18-01-009 at 9-10; D.15-07-044 at 29 (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting proceeding, but noting that the preponderance of evidence is the "default standard to be used unless a more stringent burden is specified by statute or the Courts.").
[11] Exh. PG&E-1, 1-4:28-30.
[12] D.18-01-009 at 10.
[13] *See, e.g.*, A.13-05-015, *Scoping Memo and Ruling of Assigned Commissioner*, p. 4 (September 12, 2013).

> The CCA parties are proposing changes to existing methods of calculation, and do not allege non-compliance with Commission rules, decisions, and resolutions on the part of PG&E. Such proposals should be addressed in proceedings with input from other investor owned utilities and interested parties.[14]

PG&E itself relied on this scoping ruling, and the prohibition on policy determinations in ERRA forecasting dockets, in its Reply to the Joint CCAs' Protest in the instant proceeding.[15] It argued there that rulemaking dockets apply to all of the IOUs and are noticed to, and generally include as parties, a broader set of stakeholders.[16] PG&E also quoted the Scoping Ruling for its 2014 ERRA forecasting application (A.13-05-015), which stated that "challenges to the Commission's existing policy and/or rules are beyond the scope of this proceeding and must be raised via a petition for modification of the decision that established the policy and/or rule in question."[17] Per PG&E, "[t]his proceeding is limited to a year ahead forecast for a single utility and thus is not the appropriate venue for addressing broad policy issues that impact all California IOUs."[18] Finally, with specific reference to changes to the calculations of the Market Price Benchmark, PG&E has argued that

> the proper procedural venue to propose any changes to the current methodology for calculating the PCIA, including any modifications to the MPBs, is R.17-06-026 (i.e., the PCIA OIR),[] not an individual utility's ERRA Forecast proceeding.[] Until the Commission modifies the current methodology for all IOUs in the Rulemaking, PG&E's Renewable MPB must be calculated using the methodology outlined in D.11-12-018 and Resolution E-4475.[19]

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[14] A.17-06-005, *Scoping Memo and Ruling of Assigned Commissioner,* pp. 3-4 (August 24, 2017) ("2018 ERRA Forecast Scoping Ruling").
[15] A.18-06-001, *PG&E Reply to Protests and Responses*, pp. 2-3 (July 16, 2018).
[16] *See id*. at 3.
[17] *Id*. at 2 (citing A.13-05-015, *Scoping Memo and Ruling of Assigned Commissioner*, pp. 3-4 (September 12, 2013)).
[18] *Id*. at 3.
[19] A.17-06-005, *Opening Brief of PG&E*, p. 21 (Oct. 16, 2017) (citing R.17-06-026) (internal footnotes omitted).

Despite these repeated assertions both within and outside of this docket, PG&E introduces a substantial revision to the indifference calculation methodology through its 2019 ERRA forecast application. PG&E's unsanctioned approach to allocating revenues from the sales of RA capacity and RPS generation is outside the boundaries of an ERRA proceeding and results in unlawful and unreasonable rates. These material short-comings, the misallocation of costs from DCPP, and the on-going procedural and transparency issues in PG&E's ERRA forecast proceedings require a finding that PG&E's rate proposals should not be approved.

III. PG&E's Treatment of RA and RPS Sales Revenues in its PCIA Calculation is Unprecedented, Contrary to the Law, and Unreasonable.

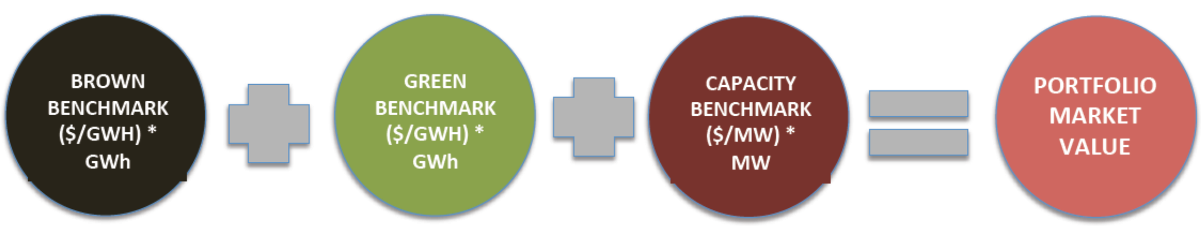
A. Commission precedent articulates the existing PCIA calculation methodology.

The Commission adopted the PCIA to ensure when IOU customers depart from bundled service and receive their electricity from a non-IOU provider, such as a CCA, "those customers remain responsible for costs previously incurred on their behalf by the IOUs — but only those costs."[20] The PCIA is derived from the utility's Total Indifference Amount,[21] which is updated annually in each IOU's ERRA proceeding.[22] To obtain the Total Indifference Amount, the market value of the IOU's supply portfolio is subtracted from the total portfolio cost.[23]

[20] R.17-06-026, *Scoping Memo and Ruling of Assigned Commissioner*, pp. 2 (Sep. 25, 2017) ("PCIA Scoping Ruling").
[21] Exh. PG&E-1, 14-1:5 to 14-4:17, Table 14-3 and Attachment A; Exh. PG&E-2, 2-7, Table 2-5 and Attachment A-1.
[22] D.11-12-018 at 8.
[23] *Id.* at 8; Exh. PG&E-5, line 24.

The Total Portfolio Cost includes UOG, purchased power such as that from power purchase agreements ("PPAs"), fuel costs, and California Independent System Operator ("CAISO") costs.[24]

The Portfolio Market Value is derived from the market price benchmark ("MPB"), an administratively determined proxy which represents the market value of the IOU's resource portfolio.[25] To obtain the market value of brown power in an IOU's portfolio, the forecasted amount of energy from such resources in the portfolio is multiplied by the brown power benchmark.[26] To obtain the market value of RPS power in an IOU's portfolio, the forecasted amount of energy from such resources in the portfolio is multiplied by the green power benchmark.[27] To obtain the market value of RA capacity in an IOU's portfolio, the monthly average RA capacity in an IOU's portfolio is multiplied by a capacity benchmark.[28] The sum of the market value of the portfolio's brown power, green power, and capacity is the Portfolio Market Value.



A distinct vintage portfolio of generation resources is calculated for each year; each vintage is assigned a separate indifference amount; and each departing customer is assigned a

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[24] D.11-12-018 at 8-9.
[25] *Id.* at 8.
[26] Exh. PG&E-5, line 10. "Brown" power is very broadly defined as non-RPS-eligible generation, so it includes large-scale hydropower, nuclear and cogeneration. *See* D.11-12-018 at pp. 17-25 (limiting the scope of the "green" adder to only include RPS-eligible generation, meaning all other power is "brown" power).
[27] Exh. PG&E-5, line 14. "Green" power is narrowly defined as RPS-eligible generation for which renewable energy credits can be issued. *See* D.11-12-018 at pp. 17-25.
[28] Exh. PG&E-5, line 18.

vintage based on the year the customer left bundled service.[29] A positive indifference amount indicates that the IOU portfolio cost is above-market for that year.[30] As seen in PG&E's Table 9-4, every vintage from 2009 to 2018 has a positive indifference amount based on the cost of the resources under contract at the time the customer departed.[31] For example, customers that left PG&E's bundled service in 2010 have a Total Portfolio Cost of approximately $5 billion[32] and a Portfolio Market Value of approximately $2.8 billion.[33] Subtracting the latter from the former, and accounting for small adjustments based on lines losses, franchise fees, and uncollectible customer balances, results in a Total Indifference Amount of approximately $2.2 billion.[34]

B. PG&E's proposed treatment of RA and RPS revenues cannot be adopted because it is new policy that does not follow any Commission rule, regulation, resolution or decision.

A major difference between PG&E's 2019 ERRA forecast and prior ERRA forecasts is that the utility is predicting large amounts of revenues from selling output in the CAISO energy and ancillary services markets, in the RA capacity market, and from RPS resources.[35] That is, PG&E forecasts it will be long on energy and capacity in 2019 and will therefore be a substantial seller of these multi-year products, *i.e.*, sales contracts PG&E signed to sell more than one year's worth of output from procurement contracts or UOG, in the market for the first time. In the past, PG&E's revenues from sales have been sufficiently small to be inconsequential for setting PCIA rates.[36] That is no longer the case.[37] PG&E forecasts receiving over $730 million dollars from

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[29] D.11-12-018 at 9.
[30] *Id*.
[31] Exh. PG&E-5, lines 28 and 29.
[32] Exh. PG&E-1, 9-15 at Table 9-4, lines 1 and 22, column 2010.
[33] *Id*. at line 23, column 2010.
[34] *Id*. at line 24, column 2010.
[35] Exh. Joint CCAs-1, 4:3-10.
[36] *Id*.
[37] *Id*.

other utilities and LSEs in sales revenues in 2019.[38] PG&E asks the Commission to resolve how to address substantial revenue for the first time in this utility-specific ratesetting proceeding,[39] to which neither of the two other IOUs nor any southern California CCAs are a party.

While PG&E has revised its approach since its initial Application, it originally proposed to allocate all revenues from multi-year RA and RPS sales to only the 2018 vintage. Under that proposal, customers who are paying the PCIA for above-market procurement costs during the earlier vintages of PG&E's portfolio, *e.g.*, in 2010, would not have received any credit for the revenues from contracts tied to that vintage.[40] Only customers who departed PG&E's service in the most recent vintage – 2018 – would receive such benefits.[41] PG&E did not provide any explanation for how or why it was assessing revenues in this manner other than general statements such as:

- "Through the course of 2019, PG&E anticipates making purchases or sales of capacity and energy when needed in addition to that provided by the current resource mix to fill short-term gaps between supply and demand and to manage excess supply."[42]
- "When the supply is greater than the demand (i.e., a physical long position), PG&E forecasts that it will be selling power to the market. … The estimated net purchase costs and sales revenues associated with these residual energy transactions are shown in Table 6-1."[43]
- "For those months when the supply is greater than the requirement (i.e., a physical long position), PG&E forecasts selling capacity. … The estimated net purchase costs and sales revenues associated with these residual capacity transactions are shown in Table 6-1."[44]

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[38] *Id*.
[39] *Id.* at 4:3-10.
[40] *Id*. at 4:14-16.
[41] *Id*.
[42] Exh. PG&E-1, 3-5:19-22.
[43] *Id.* at 6-4:30-32 and 6-5:3-4.
[44] *Id.* at 6-4:20-22, 24-26.

Thus, PG&E proposes a novel approach for a previously unaddressed issue in its Application—a practice the Commission has repeatedly disallowed in ERRA proceedings. Moreover, instead of clearly articulating this proposal in its Application and supporting testimony, PG&E left the Commission and parties to deduce from workpapers and charts the fact the proposal existed, let alone the methodology used to allocate those revenues across vintages.

The Joint CCAs appear to be the only parties that have identified this proposal and its implications. The Joint CCAs' intervenor testimony pointed out that since PG&E is selling output from its entire RA and RPS portfolio, *i.e.*, output from contracts beyond those tied to the 2018 vintage, revenues from those sales should be credited against all RA assets and RPS PPAs in proportion to those assets held in each vintage. [45]

In its rebuttal testimony, PG&E agrees its originally suggested treatment is inappropriate and, instead, proposes to allocate revenues across the applicable vintages.[46] However, again, the methodology the utility uses to do so is left substantially unexplained. For RPS sales, PG&E simply states the sales are tied to unit-specific resources from the 2007-2011 vintages and have been re-allocated across those vintages as listed in PG&E's Table 1-1.[47] For RA, PG&E states the sales are not unit-specific and are allocated on a *pro rata* basis across all vintages as listed in PG&E's Table 1-2.[48] No further explanation, justification, or Commission guidance is provided regarding this approach other than references to these tables and PG&E's workpapers. [49] PG&E then concludes its changes will increase the PCIA by another $27.3 million.[50]

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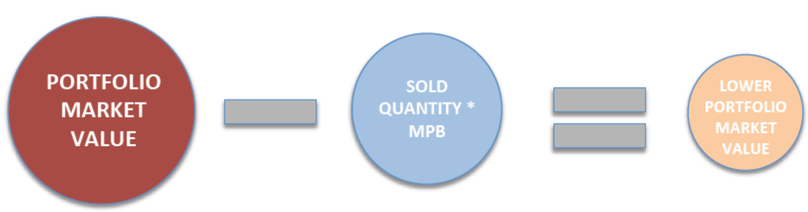
[45] Exh. Joint CCAs-1, 4:17-18.
[46] Exh. Joint CCAs-3; Exh. PG&E-2, 1-5:5-6, 1-5:16-19, and 1-7:1-3.
[47] Exh. PG&E-2, 1-5:14-22 and 1-6, Table 1-1.
[48] *Id*. at 1-7:1 to 1-8:9.
[49] *Id*. at 1-5:2 to 1-10:4.
[50] *Id*. at 1-8:10-12.

The Joint CCAs discovered the reason for the increase by digging deeply into the utility's workpapers and exhibits, submitting expedited discovery requests, and meeting with PG&E during the 13 days between the service of PG&E's rebuttal testimony and the beginning of hearings. The first factor in the increase is that PG&E reduces the amount of Total Portfolio Costs by the forecasted revenues, *i.e.*, the sales price in each individual contract to sell either RA or RPS products multiplied by the MWh expected to be sold.[51]

The second factor is that PG&E then also removes the output sold, MWh (for RPS) or MW (for RA), from the Portfolio Market Value, which lowers that value by the amount of the MW or MWh sold times the applicable benchmark within the MPB (the green benchmark for RPS and the capacity benchmark for RA).[52]



In other words, PG&E's proposed methodology reduces the Total Portfolio Cost by less than it reduces the Portfolio Market Value.

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[51] This can be seen in the decrease of Total Portfolio Cost ($) by *comparing* PG&E-1, p. 9-15, Table 9-4, line 1, for all vintages 2009-2019 *to* PG&E-5, line 1, for all vintages 2009-2019.

[52] This can be seen in the decrease of Renewable Energy (GWh) and Average Monthly NQC for purposes of calculating the MPB by *comparing* PG&E-1, p. 9-15, Table 9-4, lines 12 and 16, for all vintages 2009-2017 *to* PG&E-5, lines 12 and 16, for all vintages 2009-2017. (We cannot explain the discrepancies in PG&E's tables for the 2018 and 2019 vintages.)

The result is an increase to the Total Indifference Amount and, consequently, the PCIA.[53]

PG&E's approach effectively values sold output at a different amount than unsold output. The average price for sold output from RPS contracts is $[redacted]/MWh under PG&E's proposal.[54] In contrast, RPS contracts with unsold output are being valued at the green benchmark of $51.95/MWh.[55] The average price for sold capacity from RA contracts is $[redacted]/kW-year.[56] RA contracts with unsold output are being valued at the capacity benchmark of $58.27/kW-year.[57] In fact, because PG&E is using the actual forecasted revenues from sales, sold output is being valued at *numerous* different values (the contract price in each sales agreement), and each of those values is very likely to be different than the applicable benchmark at which unsold output is being valued.

No Commission decision allows for either PG&E's proposed treatment or for valuing sold output at a transactional value that is different than the MPB. PG&E admits as much in response to a data request from the Joint CCAs, stating neither its method for allocating revenues from RA sales nor its method for RPS sales "has been given explicit Commission approval …."[58]

[53] Exh. PG&E-2, 1-8:10-12.
[54] Exh. Joint CCAs-5-C; *see also* Exh. PG&E-2, AtchA-1, line 10.a, column Total (redacted) divided by PG&E-2, AtchA-1, line 20.a, column Total.
[55] Exh. PG&E-5, line 13.
[56] Exh. Joint CCAs-6-C; *see also* Exh. PG&E-2, AtchA-1, line 10.b, column Total (redacted) divided by PG&E-2, AtchA-1, line 30.a, column Total.
[57] Exh. PG&E-5, line 17.
[58] Exh. Joint CCAs-4.

The utility further admits discussion of its novel approach was included in its proposals within the PCIA docket, R.17-06-026.[59] Included within scope of that docket is the review, revision and consideration of alternatives to the current PCIA methodology.[60] According to PG&E, ERRA-related discussions in the PCIA docket addressed how "sales of the utilities [*sic*] long position will be credited pro-rata to the vintage portfolios," *i.e.*, the same issue the utility implicitly addresses in its Application in this docket. Thus, PG&E is proposing to *implement* here a proposal still under consideration in the PCIA docket. Worse, that proposal is part of the IOUs' Green Allocation Methodology and Portfolio Monetization Mechanism, both of which have been rejected by the current Proposed Decision ("PD") and Alternate Proposed Decision ("APD") in that docket.[61]

Both the PD and the APD in R.17-06-026 endorse the creation of a "Phase 2" to "to establish a 'working group' process to enable parties to further develop a number of proposals regarding portfolio optimization and cost reduction for future consideration by the

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[59] *Id.* (explaining PG&E "is matching the sales revenues received against the associated costs" for RPS sales, and "the default allocation is consistent with the *proposal* by the Joint Utilities in the PCIA Rulemaking, R.17-06-0275 [*sic*], whereby sales of the utilities long position will be credited pro-rata to the to the [*sic*] vintage portfolios. In the case of the RA sales, the pro-rata allocation used the percentage of MW in the vintaged portfolios to fairly allocate the sales revenues.") (emphasis added).
[60] PCIA Scoping Ruling at 22.
[61] Exh. Joint CCAs-4. *See* R.17-06-026 *Proposed Decision Modifying The Power Charge Indifference Adjustment Methodology*, pp. 17, 89-96, 117 (Aug. 1, 2018) ("PCIA PD"); R.17-06-026, *Alternate Proposed Decision Modifying The Power Charge Indifference Adjustment Methodology*, pp. 14-15, 74-77, 97 (Aug. 14, 2018) ("PCIA APD"). Therein, the Commission explains that under the Green Allocation Mechanism, "market revenues (for energy, ancillary service (A/S), and any other revenues)" from RPS resources are "assigned pro rata to all benefitting customers as an offset to the costs of those resources. Additionally, the RA and Renewable Energy Credit (REC) attributes of those resources are allocated pro rata to the LSEs serving departing load customers." Under PMM, "the RA for other portfolio resources is allocated pro rata, the departing load customers' share of which would be monetized in regularly-occurring auctions. The market revenues for energy, A/S, any other revenues (and RA monetization for departing load customers) are then assigned pro rata to all benefitting customers as an offset to the costs of those resources. The net costs of PMM resources are assigned pro rata to all benefitting customers." *See also* R.17-06-026, Exh. IOU-1 at 1-21:21 to 1-23:4 (stating "[T]he initial rates for both the PMM and GAM portions of the portfolio will be set in the Joint Utilities' respective annual Energy Resource Recovery Account (ERRA) Forecast proceedings based on a forecast of costs and offsetting market revenues (forecast net resource costs) . . . .").

Commission."[62] Those "portfolio optimization" practices may require, among other things, the IOUs to "take proactive steps to mitigate their long positions" and "reduce the stranded costs associated with out-of-market PPAs."[63] Determining the manner in which such optimization and cost reduction would be included within each IOUs' ERRA proceeding is not only procedurally premature but also improper because it could prejudge the outcomes of Phase 2 of the PCIA docket.

Even if the issue was not in scope of the PCIA docket, adopting PG&E's suggested approach constitutes the type of piecemeal policy-making the Commission has repeatedly disallowed in the ERRA proceeding.[64] ERRA forecasts are unique to each IOU. Creating new policy about sales revenues, by netting them from Total Portfolio Costs at the sales price and removing them completely from the Portfolio Market Value component of the indifference calculation, would have implications across all three IOUs' service areas. Neither Southern California Edison ("SCE") nor San Diego Gas & Electric ("SDG&E"), nor any of the CCAs in Southern California, are parties to this proceeding.[65] These issues belong exclusively in a rulemaking like the PCIA where all three IOUs, and other interested parties, are able to engage. Adopting PG&E's approach here would create the potential for either inconsistent approaches among the three IOUs or for requiring SCE and SDG&E to follow policies adopted in an application process to which they were not a party.

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[62] PCIA PD at 111; PCIA APD at 90-91.
[63] *See* PCIA PD at 105; PCIA APD at 86 (summarizing advocacy of the Association for Retail Energy Markets and Direct Access Consumer Coalition as one of a "a number of proposals regarding portfolio optimization and cost reduction for future consideration by the Commission.").
[64] *See, e.g.*, D.18-01-009 at 10; 2017 ERRA Forecast Scoping Ruling at 3-4; A.13-05-015 Scoping Memo and Ruling of Assigned Commissioner, p.3 (Sep. 12, 2013).
[65] The Joint CCAs are not parties to the ERRA applications filed by SCE and SDG&E and have not examined whether those utilities are also proposing novel treatment of sales revenues. If that is the case, the Commission should act to forestall piecemeal policymaking in those cases as well.

C. PG&E's proposal is contrary to the law.

Notably, PG&E is not assigning or selling all attributes of the RPS and RA contracts at issue but rather just *some* generation and/or capacity over the terms of those contracts. If PG&E were selling or assigning the entire above-market contracts, the utility presumably would have removed the contract costs from their PCIA-eligible portfolio in a manner similar to how it would treat an expired contract. By selling only the output, PG&E's approach keeps the entirety of the costs of each contract within its PCIA-eligible portfolio while reducing the market value of the contract.[66] This approach ignores any benefits that might continue to accrue to bundled customers from keeping the contract within the IOUs' portfolio.[67]

Such benefits are supposed to be accounted for and subtracted from departing load's indifference liability pursuant to Pub. Util. Code §366.2(g). Section 366.2(g) states the PCIA should be reduced "by the value of any benefits that remain with bundled service customers" from contracts that are kept within PG&E's portfolio.[68] Flawed as it may be, the Commission's current proxy for the market value of *all* benefits from contracts that remain in the IOUs' portfolio is the MPB.[69] By valuing contracts that remain within the IOUs' portfolio based solely on short-term sales revenues, instead of the MPB, PG&E's approach ignores any potential benefits that may remain with bundled customers and, therefore, is unlawful.

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[66] *See* n. 51-53, *supra.*

[67] As documented extensively by the California Community Choice Association in the PCIA docket, R.17-06-026, these benefits can include hedging, *i.e.*, the premium paid to gain certainty regarding market pricing, and compliance "buffers," *i.e.* providing a "buffer" for changes in the market, load levels or load shapes that would result in shortfalls in meeting statutory or Commission-established requirements.

[68] Cal. Pub. Util. Code § 366.2(g).

[69] *See* D.11-12-018 at 8.

D. PG&E's proposed treatment is unreasonable because it creates the potential for gaming the PCIA and is administratively burdensome for the Commission or other stakeholders to verify.

Forecasting the value of contracts at a transactional level instead of the MPB creates the potential for gaming. PG&E can choose to sell output from projects with the largest differences between the initial contract price and the recent sales price. Sales of higher-cost contracts would remove the same MW or MWh from the Portfolio Market Value as sales of lower-cost contracts, meaning the impact on the market value component of the indifference calculation would be the same. However, PG&E's choice to sell output from higher-cost contracts will keep more costs in the Total Portfolio Cost than would a sale from lower-cost contracts and, all other factors being equal, will increase the PCIA as a result.

The approach is also administratively burdensome. Unlike the assignment of an entire PPA, these sales could be for incomplete products. That fact requires an investigation into the terms of each contract to understand a number of factors, such as whether revenues may change over the course of the forecasted year, whether the sold quantities are constant throughout the year, whether unsold quantities remain within the contracts, and whether the agreements are recallable or modifiable in any fashion over the course of the forecast year. Indeed, in this proceeding, PG&E did not provide the data on individual sales until prompted by the Joint CCAs direct testimony, forestalling any opportunity for in-depth review. Proper valuation and allocation across the vintages cannot be done without such data, and it is unlikely such an investigation can be completed in the short time allowed in an ERRA proceeding. This question of verification is ripe for consideration in the anticipated second phase of the PCIA proceeding and is inappropriate for a single utility's ERRA forecast proceeding.

E. The Joint CCAs' approach fosters a proper application of prior Commission direction on sales revenues and Section 366.2(g) of the Public Utilities Code.

The treatment of anticipated sales revenue within ERRA forecast proceedings for departed customers is an undoubtedly important issue as the IOUs transform into major sellers of energy and capacity. If the Commission wishes to address the issue in this docket, perhaps only on an interim basis until a more comprehensive framework is put in place via R.17-06-026 or another docket, it can follow an approach it already endorsed in D.18-01-009 for revenues from sales in the CAISO spot market. In that decision, the Commission stated:

> The CAISO revenues received from spot sales are reflected in the increased market value of the generation portfolio and, therefore are "netted" out of the PCIA calculation. The reason that CAISO revenues are netted against the costs to serve bundled customers only, and not also credited to departed customers, is because departed customers have already received the benefit of the CAISO market revenues through the application of the Market Price Benchmark (MPB).[70]

PG&E endorses a similar approach in this proceeding for revenues from CAISO market sales, stating:

> [E]ven though D.11-12-018 did not specifically address sales, it should be noted that *the indifference calculation already accounts for market sales of generation by using the brown power MPB as the proxy value for market revenues received for the expected generation*.[71]

Under this approach, revenues from short-term sales of energy at CAISO are credited against the Total Portfolio Cost for departed customers at the MPB.

[70] D.18-01-009 at 12.
[71] Exh. PG&E-2, 1-3:21-25 (emphasis added).

Stated another way, all generation and capacity, whether sold or not, remains in the Portfolio Market Value. The Commission's statement in D.18-01-009 is the only guidance on how to treat revenues from sales of output from PCIA-eligible contracts.

The Joint CCAs' suggested treatment for allocating revenues from RPS and RA sales contracts across the vintages follows this approach.[72] Dr. McCann's methodology takes output sold from RA and RPS contracts and credits it to the Total Portfolio Cost of departed customers as the product of the expected sales times the MPB. This approach also matches the credits to the appropriate vintages based on quantities sold from specific RPS contracts and from system sales of RA capacity.[73] Thus, in contrast to PG&E, the Joint CCAs have proposed a treatment of RA and RPS sales that would align with the direction the Commission previously suggested for revenues from CAISO spot market sales. The result is a $9 million reduction in the PCIA revenue requirement of $1.068 billion.[74]

The Joint CCAs' approach also complies with §366.2(g) because it continues to value the contracts at the MPB, ensuring any long-term benefits from the contracts are accounted for. If the Commission chooses to address the sales revenue issue in this proceeding, on an interim

[72] Exh. Joint CCAs-1, 4:17 to 5:18, p. 10, Table 9-1 Revised, and p. 11, Table 9-4 Revised.
[73] In its rebuttal testimony, PG&E pointed out errors made in the Joint CCAs' original allocations. Exh. PG&E-2, 1-8:20 to 1-10:4. Those errors, as well as a mathematical error that had resulted in over-counting short-term RPS sales, were addressed in the revised version of the Joint CCAs testimony entered into evidence at the September 20, 2018 hearing in this proceeding. 1 Tr. 6:19 to 7:6 and 7:22 to 8:19 (McCann) (Sep. 20, 2018).
[74] Exh. Joint CCAs-1, 5:12; PG&E-1, 9-12.

basis or otherwise, it should adopt the Joint CCAs' treatment and order PG&E to follow this approach when implementing rates effective January 1, 2019.

Alternatively, if the Commission does not adopt the Joint CCAs' treatment of sales revenues, it should require PG&E to track earned revenues in a balancing account until the Commission addresses how to treat forecasts for such revenues. Such an approach will provide sufficient time to allow the PCIA or another rulemaking to address how to resolve the issue and will ensure any under- or over-collections based on the later-adopted methodology can be recovered.

IV. Commission Guidance is Needed to Correct PG&E's Forecasts for Costs Related to Diablo Canyon in Either This Proceeding or Another Forum.

Key problems with PG&E's forecast of costs from DCPP manifest themselves in the Application. The underlying issue is that the utility has included capital additions for refueling and going-forward maintenance and operations costs in its Utility Generation Base Revenue account (or UGBA) that should have been included in the ERRA revenue requirement because they are generation costs.[75] By excluding these costs from the ERRA revenue requirement, PG&E is effectively bidding DCPP into the CAISO markets at a price that is \$3.03/MWh less than it should be, *i.e.*, at its true going-forward cost.[76] "This means the CAISO is not making the decision to dispatch Diablo Canyon based on fully cost-based market bids, but instead PG&E is scheduling Diablo Canyon based on its own internal assessment of costs and market value."[77]

The Joint CCAs raise the issue here because PG&E's bundled customers do not need DCPP's output, meaning "the day has already arrived where almost the entire output of the Diablo Canyon Power Plant could be sold into the CAISO day-ahead and real-time markets to

[75] Exh. Joint CCAs-1, 6:14-17.
[76] Exh. Joint CCAs-1-C, 6:17 to 7:18. PG&E made public the \$3.03/MWh figure in its rebuttal testimony. *See, e.g.,* Exh. PG&E-2, 1-10:15-17.
[77] Exh. Joint CCAs-1, 7:14-16.

serve load other than that of PG&E's bundled customers."[78] The Joint CCAs put forth two proposals to address this issue: (1) revise the brown power component of the MPB to address the issue or (2) reduce each vintage's Total Portfolio Cost by $3.03/MWh of anticipated generation from DCPP.[79] Other than an unexplained, brief statement that the Joint CCAs' forecast is "flawed," PG&E's rebuttal testimony does not take issue with the substance of the argument but rather raises scoping and procedural concerns. [80]

Essentially, PG&E argues that outcomes from the PCIA docket may address the issue.[81] The Joint CCAs do not entirely disagree since the creation of a GHG adder within the MPB,[82] or eliminating UOG like DCPP from the pool of PCIA-eligible resources, both of which are in scope in that docket, would likely resolve the question from the perspective of unbundled customers. However, as not-for-profit government entities, the Joint CCAs are not pursuing financial gain in their advocacy in this or any other proceeding. The purpose of the Joint CCAs' advocacy is to seek comprehensive solutions that provide benefits for all ratepayers and not to focus narrowly on one group of Californians to the detriment of another group. Thus, even if the PCIA docket makes *unbundled* customers whole on DCPP-related issues, a conversation on the treatment of these costs still needs to take place either here or in another forum for the benefit of *bundled* customers.

The Joint CCAs believe the Commission can and should take two actions in this proceeding, neither of which is mutually exclusive. First, it can adopt one of the Joint CCAs' proposals to address the issue on an interim basis until it is resolved elsewhere. Second, it can make clear the appropriate venue for correcting the treatment for capital additions related to

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[78] *Id.* at 6:6-9.
[79] Exh. Joint CCA-1-C, 9:4-19.
[80] Exh. PG&E-2, 1-11:28 to 1-12:16.
[81] *Id.*
[82] Exh. Joint CCAs-1, p. 9, n. 21.

refueling, and other going-forward maintenance and operation costs, which would seem to be PG&E's general rate case. Addressing this underlying issue will provide guidance to PG&E on how DCPP should be bid into the CAISO markets, and, if that guidance is not followed, the Commission should closely review "PG&E's bidding practices with respect to its least cost dispatch activities" in the utility's ERRA compliance docket.[83]

V. Persistent Procedural and Transparency Issues Within the ERRA Must Be Addressed Comprehensively.

The Joint CCAs are advocates for the customers in the local communities that formed them. Those communities' goals are to procure cleaner, less expensive energy and use the savings to offer programs the members of those communities need, such as those targeting disadvantaged and other vulnerable populations. Planning for changes to the PCIA, and protecting customers from the rate shock that can result, is a core directive for all CCAs and essential for any LSE.

Time and again, the opacity and shortened timeframes of the current ERRA framework have frustrated these aims, and the Joint CCAs seek the Commission's guidance on the proper forum in which to address the clear shortcomings of the current process. In this docket, as discussed extensively above, PG&E proposed a substantial shift in policy, but it did not mention the shift's existence or explain the reasoning for it in prepared testimony. Rather, investigating the answers took substantial time and effort to sift through dense and inscrutable workpapers and submission of repeated rounds of discovery.

PG&E's prepared testimony in this proceeding also suggested a substantial reduction in the generation revenue requirement for bundled customers to $0.08960 cents per kWh.[84] This

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[83] A.18-02-015, *Assigned Commissioner's Scoping Memo and Ruling*, p. 5 (May 14, 2018).
[84] *See, e.g.,* PG&E-2, 2-AtchA-2-2, line 66. PG&E did not include a full, bottom up derivation of its bundled customer generation rate in its direct testimony, meaning parties were left to derive the figure.

reduction was the focus of much attention and numerous data requests from the Joint CCAs due to its impacts on the position of CCAs' generation rates relative to those of PG&E.[85] It was not until a meet-and-confer and subsequent data request responses that it was clarified that

> [u]pdates to other components of PG&E's Generation rate are addressed in other proceedings (e.g., General Rate Case) and are presented in PG&E's Annual Electric True-up (AET) Advice Letter, which consolidates approved revenue requirements and pending revenue requirements from other proceedings that are expected to be approved by December 2018.[86]

Thus, utility generation under-collections in the AET will be allocated to bundled customers, and the actual forecasted system bundled generation rate in the AET is forecasted to rise to 9.866 cents per kWh (although the final number will not be known until later this year).[87] The lack of clarity on this issue from the outset left market participants representing millions of customers unable to rationally plan for and reasonably anticipate near-term rate impacts.

Whether intentional or not, the opacity of the Application, coupled with the shortened timeframe of the proceeding, and varying levels of participation from other entities representing ratepayer interests from year to year, favors PG&E because the utility "holds all the cards." Without clear upfront explanations regarding revenue requirements or proposed changes to policy, parties are left to slog through dense Excel spreadsheets, painstakingly connecting one cell to another to determine what exactly the utility is proposing and how it will impact

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See, e.g., Exh. Joint-CCAs-9.

[85] *See, e.g.*, A.18-06-001, *Protest of East Bay Community Energy, Marin Clean Energy, Monterey Bay Community Power, Peninsula Clean Energy, Pioneer Community Energy, and Sonoma Clean Power Authority to Application of Pacific Gas and Electric Company for 2019 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation*, pp. 1-2 (July 5, 2018); Exhs. Joint CCAs-2, Joint CCAs-7, Joint CCAs-8, and Joint CCAs-9.

[86] Exh. Joint CCAs-2. *See also* Exh. Joint CCAs-7.

[87] *See* Exh. Joint CCAs-7.

customers. Even then, confirmation of those analyses can only be obtained from a discovery process that is frequently less than helpful in providing clear answers and explanations.

The Joint CCAs appreciated PG&E's willingness to meet to explain the intricacies of some of the components of its Application and will endeavor to request similar meetings with regard to the November update and future ERRA forecast proceedings. However, we seek Commission guidance for a forum in which more concrete procedural mechanisms, such as planned workshops soon after the application is filed, use of the modified non-disclosure agreement from the PCIA proceeding to allow counsel access to confidential workpapers, expedited discovery timelines, a longer procedural schedule, or other mechanisms might be discussed among all IOUs and other stakeholders.[88]

Unfortunately, the PCIA docket does not include revisions to the ERRA framework within its scope since the transparency and data access issues in that docket were limited to modifying the PCIA and not the procedural mechanics of the ERRA forecast proceedings.[89] In reforming the PCIA, the Commission first initiated a working group within A. 14-05-024 and required the working group to submit its recommendations as either petitions to modify or petitions for rulemaking.[90] The Joint CCAs suggest a similar approach here to addressing transparency and timing issues in ERRA forecast proceedings, and note the following may be good places to house the working group:

- A "Phase 2" to this proceeding, similar to what occurred in A.14-05-024;[91]
- A consolidated "Phase 2" to the IOUs' on-going ERRA forecast proceedings; or

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[88] *See, e.g.,* 2017 ERRA Forecast Scoping Ruling at 4 (stating "It would be inappropriate for the Commission to adopt new confidentiality rules in the ERRA forecast proceeding for one utility. As in the PHC, we encourage market participant parties to work closely with non-market participant parties, such as ORA, that may access confidential data to conduct the needed examinations.").
[89] PCIA Scoping Ruling at 15-23.
[90] D.16-09-044 at 20.
[91] *Id.* at Ordering Paragraph 20.

- The PCIA docket.

Regardless of the mechanism chosen, Commission guidance is needed to provide a means to discuss ways the ERRA process can be revised to ensure all LSEs can plan for and protect their customers from unnecessary rate impacts in a timely and transparent manner.

VI. Conclusion

For the foregoing reasons, the Joint CCAs respectfully request the Commission:

- Determine the calculations and entries underlying the proposed PCIA rates are not in compliance with all applicable rules, regulations, resolutions and decisions for all customer classes;

- Reject PG&E's requested 2019 ERRA Forecast PCIA revenue requirement of $1.068 billion as unreasonable;

- Adopt the Joint CCAs approach to sales revenues on either an interim or permanent basis, reducing the $1.068 billion PCIA revenue requirement by $9 million; or, in the alternative, require sales revenues be tracked in a balancing account until the Commission determines the appropriate forecasting methodology;

- Adopt one of the Joint CCAs two suggested approaches to addressing the misallocation of costs related to DCPP; or, in the alternative, provide clear guidance on where the issue should be addressed;

- Provide clear guidance on where on-going procedural and transparency issues related to the mechanics of the ERRA process should be addressed; and

- Until the issues listed herein are appropriately addressed, reject approval of PG&E's rate proposals to be effective on January 1, 2019.

Respectfully submitted,

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Dated: October 2, 2018

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)

MARIN CLEAN ENERGY'S COMMENTS ON THE PROPOSED DECISION OF ALJ ROSCOW MODIFYING THE POWER CHARGE INDIFFERENCE ADJUSTMENT METHODOLOGY

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August 21, 2018

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MARIN CLEAN ENERGY'S COMMENTS ON THE PROPOSED DECISION OF ALJ ROSCOW MODIFYING THE POWER CHARGE INDIFFERENCE ADJUSTMENT METHODOLOGY

Pursuant to the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Rule 14.3, Marin Clean Energy ("MCE") submits the following comments in response to the *Proposed Decision of ALJ Roscow Modifying the Power Charge Indifference Adjustment Methodology* ("Proposed Decision" or "PD"), issued August 1, 2018.

INTRODUCTION

MCE appreciates the opportunity to provide comments on the Proposed Decision and its careful analysis and conclusions on how to achieve the indifference principle. Unfortunately, the PD is largely silent on the failure of the Investor-Owned Utilities ("IOU") to appropriately forecast departing load due to Community Choice Aggregation ("CCA") programs and leaves the issue unresolved going into Phase II.

MCE limits its comments to the discrete issue of IOU forecasting as it relates to determination of CCA customers' cost responsibility for executed utility power contracts paid through the Power Charge Indifference Adjustment ("PCIA"). MCE supports the positions put forth by the California Community Choice Association ("CalCCA") through its testimony, hearings, and briefing in the instant phase on this issue. MCE supports the positions taken in this proceeding by CalCCA on all other issues not addressed in these comments.

MCE agrees that the Commission has "acted in this proceeding to determine with unprecedented precision the nature of the costs incurred by the Joint Utilities . . . ."[1] Without addressing IOU forecasting, however, it is premature to conclude that the PCIA methodology the PD adopts "only include[s] legitimately unavoidable costs and account[s] for the IOUs' responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize above-market costs."[2] The IOUs' demonstrated rejection of the Commission's forecasting practices resulted precisely in *avoidable* costs and *mismanaged* portfolios that *increased* above-market costs assigned to CCA customers. Failure to acknowledge this jeopardizes the legal and factual integrity of the Proposed Decision and ultimately frustrates Phase II's "promise of meaningful progress toward reducing the levels of above-market costs going forward."[3]

MCE respectfully requests the Commission address deficient utility forecasting practices in the instant phase. CalCCA demonstrated that the IOUs' historical forecasting practices violated the indifference principle by assigning un-attributable and avoidable costs to CCA customers. In Pacific Gas and Electric Company's ("PG&E") case, CalCCA demonstrated that PG&E made resource commitments in 2010 for customers it knew were going to depart bundled utility service. Any resources acquired with knowledge of departure could not reasonably be expected to serve and benefit that departing CCA load; benefits flowed to PG&E's bundled load and aided achievement of PG&E's Renewable Portfolio Standard ("RPS") targets. These procurement costs in 2010 are both avoidable and un-attributable to MCE's 2010 vintage--continuing to charge

[1] Proposed Decision at p. 120.
[2] *Id*.
[3] *Id*.

MCE's or other CCAs' customers for costs accrued in the face of imminent CCA departing load undermines indifference and violates statutory requirements.

To cure the PD's legal and factual errors surrounding IOU forecasting, MCE respectfully requests the following revisions:

- The Commission should acknowledge the IOUs' demonstrated failure to forecast and account for CCA departing load--the demonstrated deficiencies in the IOUs' historical CCA forecasting practices have created avoidable cost responsibility for CCA customers for contracts that cannot reasonably be attributed to those customers.
- The Commission should acknowledge that the IOUs' historical failure to forecast violates the indifference principle.
- The Commission should direct the utilities in Phase II to identify, with precision, the procurement commitments that have been attributed to CCA customers, but were made with knowledge of CCA departing load and with no accompanying change to the procurement plans to account for those departures. CCA departing load customers should be exempt from paying any such costs.
- The Commission should reinforce past Commission directives and order that the IOUs shall not attribute costs to departing load CCA customers for resources procured once an IOU has reasonable evidence of departure and the IOU fails to modify its procurement to account for the departure.
- The Commission should protect CCA customers from deficient IOU forecasting and prohibit the IOUs from allocating uneconomic and avoidable costs for contracts executed after CCA load departs bundled utility service.

- The Commission should direct the IOUs to use a probabilistic approach to forecast CCA departing load and file a scenario-based assessment of potential long-term load departures to appropriately capture future CCA load departures and mitigate the potential for excess utility resources and increased costs.[4]
- Going forward, the Commission should direct that CCA customers are exempt from cost responsibility for IOU contracts executed in a certain year up to the amount of departing load forecast for that year because such costs are avoidable by the IOUs if they properly forecast their load.

DISCUSSION

The PD commits legal and factual error by failing to substantively address PG&E's, Southern California Edison Company's ("SCE"), and San Diego Gas and Electric Company's ("SDG&E") ("collectively "Joint Utilities") forecasting practices. The PD draws no conclusions about the necessity of proper utility forecasting. Nor does the PD acknowledge that CalCCA demonstrated that the IOUs' refusal to forecast and account for CCA departing load violated the indifference principle and unlawfully attributed costs to CCA customers for resources that could not be expected to serve that load. The PD's omissions facilitate and continue an impermissible, avoidable, and correctable cost shift to CCA customers. This cost shift primarily affects earlier vintage CCA customers, such as those enrolled in MCE, but this failure to forecast has lingering unlawful cost shifting effects for all CCA departing load.

The PD is clear that this proceeding should "prevent cost increases for CCA customers . . . as a result of an allocation of costs that were not incurred on behalf of the departing load[.]"[5]

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[4] *See* Opening Brief of the California Community Choice Association (Public Version), filed June 1, 2018 ("CalCCA Brief") at pp. 102-03.
[5] Proposed Decision at p.13; *see also* Pub. Util. Code Section 365.2.

Through hearings and briefing, CalCCA demonstrated a PG&E strategy that created precisely this prohibited result.[6] There were cost shifts to MCE customers resulting from early PG&E RPS contract costs being allocated to MCE customers despite PG&E's substantial knowledge of MCE's imminent and actual departing load. The Commission must formally acknowledge that PG&E's past deliberate failures to forecast and account for CCA departing load in its procurement and cost allocations have unlawfully assigned costs to CCA customers, otherwise the PD retains errors of fact. The Commission must also eliminate cost shifts due to the IOUs' historical forecasting practices for CCA customers and ensure symmetrical and lawful application of the indifference principle to both bundled and CCA customers going forward, otherwise the PD commits an error of law.

A. The PD Should Be Revised to Prohibit the Joint Utilities from Allocating Above-Market Costs for Contracts Executed Once the IOU Has Reasonable Notice of Departure and Fails to Adjust Its Procurement to Account for the Anticipated Departures.

According to statute, departing load CCA customers are only responsible for unavoidable above-market costs attributable to those customers.[7] Moreover, CCA customers' costs cannot increase due to allocation of costs not incurred on their behalf.[8] A cost can be reasonably attributable to customers only if a utility procures a resource to serve those customers. Since 2004, the Commission has expected the utilities to forecast departing load to mitigate the risk of unnecessary resource commitments that may be stranded due to anticipated departing load. The Commission has been clear that the utilities should "us[e] available information to forecast customer demand and should incorporate CCA load losses into their planning efforts, just as they

[6] CalCCA Brief at pp. 99-103.
[7] Pub. Util. Code Section 366.2(f)(2).
[8] Pub. Util. Code Section 365.2.

would include any other forecast variable related to expected changes in supply or demand."[9] The PD also cites the Commission's early directive that the utilities "acknowledge potential CCA departing load and identify which city and/or county has expressed intent to pursue aggregation, including MW estimates of this departing load, in future procurement plans."[10] CalCCA demonstrated that the IOUs ignored these directives. In particular, PG&E departed from statutory and Commission directives by allocating costs to MCE customers for resources PG&E had every reason to conclude would not serve those customers. PG&E's conduct created avoidable and unreasonable costs for CCA customers for which they are not responsible.

1. SCE and PG&E Ignored CCA Departing Load in Their Procurement Planning Leading to Avoidable and Un-Attributable Costs Being Shifted to CCA Customers.

The Commission is tasked with ensuring 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."[11] At hearings, SCE and PG&E confirmed that they effectively disregarded the Commission's guidance in Decision 04-12-046 and Decision 04-12-048 by choosing to establish a narrowly defined threshold for forecasting departing load.[12] The IOUs' unlawful failure to forecast effectively justified utility procurement on behalf of departing load for as long as possible, even though all indications were that load would depart.[13] Particularly in the early years of CCA departure, this deviation from Commission directive allowed the utilities to completely ignore the potential for dramatic increases in CCA customer departure. As a result, IOU forecasts failed to appropriately inform their long-term procurement contracting, which has affected cost allocation

[9] Decision 04-12-046 at p. 30.
[10] Decision 04-12-048, Ordering Paragraph 9 at p. 239.
[11] Pub. Util. Code Section 365.2.
[12] *See* 4 Tr. 809: 20-810: 3 (Cushnie); 4 Tr. 813: 9-10 (Lawlor); 4 Tr. 817: 13-820:16 (Lawlor); 821: 26-822:3 (Lawlor); 5 Tr. 857: 13-21 (Lawlor); *see also* CalCCA Brief at pp. 98-99.
[13] 4 Tr. 817: 13-820: 16 (Lawlor); 821: 26-822:3 (Lawlor); 5 Tr. 857: 13-21 (Lawlor).

for 20-30 year financial commitments made by the utilities.[14] In fact, it was not until after Decision 14-02-040 that the utilities started forecasting CCA departing load in their bundled procurement plans due to a Commission order. The fact that this order came four years after MCE began serving customers demonstrates an unlawful cost shift to CCA customers for *avoidable* costs *not* attributable to their departure but instead due to PG&E's negligence and deliberate failure to forecast.

2. PG&E Willfully Ignored MCE's Departing Load in 2010 and Failed To Adjust Its Portfolio Causing Illegal Allocation of Cost Responsibility to MCE Customers for Avoidable Costs Not Attributable to MCE Customers.

With respect to MCE's launch in 2010, the record establishes that PG&E failed to follow even its own narrowly defined threshold for CCA forecasting. The record demonstrates that PG&E was aware of MCE's (then Marin Energy Authority) intention to launch in 2010 via MCE's submitted and CPUC-certified implementation plan.[15] Indeed, PG&E was certainly well-aware of the formation of MCE before MCE submitted its implementation plan. This is demonstrated by PG&E's contribution of $44 million in funding for the creation and promotion of Proposition 16, a statewide ballot initiative aimed to prevent CCA formation and that ultimately lead to legislative and Commission intervention to constrain PG&E's egregious and obstructive behavior.[16]

Notwithstanding PG&E's anti-CCA campaign, MCE's implementation plan indicated load in 2010, including forecast load growth through 2019, and indications of active negotiations for long-term power contracts to serve this load.[17] Yet, PG&E proceeded to execute contracts in 2010 (representing approximately 1.7 GW of capacity)--all of which were executed after MCE

[14] *See* CalCCA Brief at pp. 97-103.
[15] 4 Tr. 817: 13-820: 16 (Lawlor); 821: 26-822:3 (Lawlor); 5 Tr. 857:13-17 (Lawlor); 5 Tr. 857:18-21 (Lawlor); *see also* CalCCA Brief at p. 99.
[16] *See* Senate Bill 790 (Stats. 2011, Ch. 599; *see also* Decision 12-12-036.
[17] 4 Tr. 820: 11-16 (Lawlor).

submitted its implementation plan, some of which were executed after certification of MCE's implementation plan by the Commission, and approximately 600 MW of which was executed after MCE launched.[18]

Despite clear knowledge of MCE's launch, forecasted long-term load growth, and MCE's 2010 long-term contracting efforts,[19] PG&E continued to assign cost responsibility to MCE's 2010 vintage for this 2010 procurement.[20] In this particular instance, cost responsibility is not due to PG&E's deficient forecasting, it is due to PG&E's deliberate tactic to ignore both forecasted *and* actual CCA departures and failure to adjust its portfolio and costs accordingly.[21] The resources secured in 2010 should never have been assumed to serve MCE's 2010 vintage because PG&E was keenly aware that load would be departing or had already departed. Therefore, the above-market costs allocated to MCE's 2010 vintage are certainly not "unavoidable" as required by statute. The Commission must acknowledge and correct the illegal and persistent allocation of costs to MCE customers that resulted from PG&E's deliberate ignorance of all notice of MCE's imminent and actual departure.

3. MCE's and Other CCAs' Departing Load Experience Cost Shifts Resulting from Deficient IOU Forecasting Because They Bear Cost Responsibility for Contracts Executed by their CCA in Addition to Avoidable, Un-Attributable Above-Market Costs Allocated to Them by the IOUs.

MCE and other CCA customers retain cost responsibility for PG&E's avoidable 2010 above-market procurement costs to this day.[22] The IOUs' "narrowly-defined departing load forecasting approach completely missed the potential for the dramatic increases in departure that

[18] *See* Exh. CalCCA-123, Maximum Contract Capacity; *see also* Exh. CalCCA-123, PG&E 2010 Contract Execution Dates from Attachment 10 ALJ Requested Data Matrix. .
[19] 4 Tr. 819: 1 – 822:3 (Lawlor).
[20] *See* CalCCA Brief at 98-99.
[21] *See id*. at pp. 100-01.
[22] *See* Exh. CalCCA-123, PG&E 2010 Contract Execution Dates from Attachment 10 ALJ Requested Data Matrix.

[ ] are being experienced now."[23] This IOU strategy of assuming minimal to no CCA load departure has amplified rate impacts on CCA customers because CCA customers are paying twice; they are responsible for IOU above-market procurement costs in addition to the costs associated with their CCA's procurement. In particular, MCE's early vintages until D.14-04-020 are not only allocated above-market costs for those PG&E resources secured with substantial notice of MCE's departure, but they are also bearing duplicative cost responsibility for procurement MCE was obligated to make on behalf of its customers as their new Load Serving Entity. Moreover, many of MCE's early contractual obligations are subject to the same dramatic above-market cost concerns faced by the Joint Utilities. No widespread socialization of these above-market costs is possible for these CCA customers. Forcing CCA customers to pay twice for above-market resources because of negligent utility planning violates the indifference principle. The PD commits legal and factual error by failing to acknowledge and resolve this unjust and unreasonable cost shift to CCA customers. Unless and until this is resolved, the full potential of this phase of the proceeding is unfulfilled: unprecedented determination of the nature of the costs incurred by the Joint Utilities.[24]

4. CCA Departing Load Customers Subsidizing PG&E's RPS Targets for Its Bundled Load Creates an Illegal Cost Shift to CCA Customers.

CCA customers' PCIA cost responsibility must be reduced "by the value of any benefits that remain with the bundled customers . . . ."[25] Most astonishing, given the emphasis in this proceeding on attaining the indifference principle, PG&E defended its historical forecasting and admitted that it would not have made any procurement decisions based on the anticipated CCA

[23] CalCCA Brief at pp. 98-99.
[24] *See* Proposed Decision at p. 120.
[25] Pub. Util. Code Section 366.2(g).

load departure MCE represented.[26] In fact, PG&E admitted that it would take load departures of up to 10-20 percent before PG&E adjusted it procurement practices.[27] Continuing to charge CCA customers for resources an IOU has reason to believe will not serve those customers and further failing to adjust procurement and cost allocations accordingly violates indifference.

With specific reference to MCE in 2010, PG&E indicated that its 2010 executed contracts were "purchased . . . knowing that [PG&E] needed to meet its RPS targets on a total portfolio basis . . . We don't manage to a departure. We had an open need, and we manage it in a bundled way."[28] MCE's 2010 vintage should never have been attributed costs or benefits from PG&E's procurement in that year because PG&E had every reason to know and plan for MCE's departure.[29] Moreover, the fact that no amount of CCA departures up to 10-20 percent would be cause to change procurement practices strongly implies bundled customers retained substantial benefit from departing CCA load--either PG&E continues to hold all of its resources acquired prior 10-20% CCA departure for the benefit of bundled customers or PG&E failed to act in accordance with state law and Commission policy to forecast departing load and manage its portfolio accordingly. Both scenarios violate indifference.

The Commission's final decision in this phase must acknowledge this unlawful practice and commit to resolving the resulting cost shifts to CCA customers due to IOU, and particularly PG&E's, forecasting practices in Phase II. Failure to do so results in both an error of fact and an error of law because it results in an asymmetrical application of the indifference principle. CCA customers reasonably anticipated to depart are forced to subsidize PG&E's efforts to achieve its RPS targets, while the procurement benefits flow to bundled customers.

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[26] 4 Tr. 822: 24-823: 20 (Lawlor); 5 Tr. 853:25-854:1 (Lawlor).
[27] 1 Tr. 37:17-21 (Wan).
[28] 4 Tr. 822: 24-823: 20 (Lawlor).
[29] CalCCA Brief at pp. 99-100.

B. The Commission Should Direct the Joint Utilities to Use a Probabilistic Approach to Forecasting CCA Departing Load and Require the IOUs to Prepare and File Scenario-Based Assessment of Long-Term CCA Departing Load.

The PD must direct the Joint Utilities to properly forecast CCA departing load and alter their portfolio management practices accordingly using a probabilistic forecasting approach. Failure to do so is factual and legal error because it would ignore reasonable and achievable steps towards indifference and fail to eliminate future cost shifting due to poor IOU forecasting. Commission reinforcement of Decision 14-04-020 on this issue is crucial given estimates in this proceeding of potential load departure of up to 85%. The proceeding has demonstrated that reliance on the Binding Notice of Intent does little to mitigate cost shifting, particularly in a situation where the Joint Utilities are long on their RPS resources. The Commission should direct in the instant phase that the Joint Utilities return to a "common sense" forecasting practice as the Commission articulated it in D.03-04-030.[30] The utilities already use such an approach for their large industrial and agricultural customers.[31] The same practice should apply to CCA departing load.

To complement and facilitate more aggressive IOU forecasting of CCA departing load, the Commission should direct the IOUs to file scenario-based assessments of the potential long-term range of future load departures.[32] As part of this filing, the IOUs should demonstrate that their resource plans are able to adapt to changing supply obligations due to future load departure scenarios.[33] The Commission is obligated to take active steps to uphold indifference. Failure to revise the PD and direct the IOUs to adopt more aggressive forecasting of CCA departing load will encourage and facilitate additional illegal cost shifts to CCA customers.

[30] *Id*. at p.102.
[31] *Id*.
[32] *Id*. at p. 103.
[33] *Id*.

C. The Commission Should Direct that CCA Customers Be Exempt from Contracts Executed in a Certain Year up to the Amount of Departing Load Forecast for that Year.

Going forward, the Commission should take steps to ensure that forecasted departing load is not attributed cost responsibility for contracts executed in a certain year up the amount of departing load forecast for that year.[34] Assigning cost responsibility for such contracts violates indifference because such costs are avoidable if the IOUs are properly forecasting their load. If the utility excludes an amount of departing load in establishing its procurement plan using the probabilistic forecasting approach advocated for by CalCCA, any procurement under the procurement plan cannot be mischaracterized as attributable to that departing load, consistent with D.03-04-030. Moreover, exclusion of that CCA departing load from cost responsibility would mitigate duplicative procurement and costs that would be borne by CCA customers.

CONCLUSION

MCE thanks Commissioner Peterman and Administrative Law Judge Roscow for their thoughtful consideration of these comments.

Respectfully submitted,

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[34] *Id*.

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APPENDIX

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, Marin Clean Energy offers the following index of proposed changes to the Findings of Fact and Conclusions of Law to the *Proposed Decision of ALJ Roscow Modifying the Power Charge Indifference Adjustment Methodology*. MCE's proposed revisions appear in italics.

Proposed Modifications to Findings of Fact

29. Proper utility forecasting of CCA departing load is necessary to ensure indifference.

30. Since 2004, the Commission has directed the Joint Utilities to forecast CCA departing load using all available information and modify their respective loads accordingly to mitigate excess procurement and costs.

31. The Joint Utilities' historical forecasting practices did not allow for forecasting of large scale CCA departing load.

32. The Joint Utilities' historical forecasting practices departed from prior Commission direction, which has created avoidable above-market costs that are not be attributable to CCA departing load customers.

33. PG&E failed to acknowledge all reasonable and available information regarding Marin Clean Energy's launch in 2010 in its procurement planning.

34. PG&E was well aware of Marin Clean Energy's likely departure in advance of Marin Clean Energy filing its implementation plan due to PG&E's aggressive anti-CCA campaign activities, which ultimately lead to passage of Senate Bill 790 and lead to the Commission's adoption of the Code of Conduct.

35. PG&E's failure to acknowledge all reasonable and available information regarding Marin Clean Energy's launch in 2010 in its procurement planning resulted in Marin Clean Energy customers being attributed costs for procurement in 2010 that could not have reasonably been expected to serve that load.

36. PG&E has done nothing to adjust its portfolio following the departure of CCA load until very recently, despite far more load departure than 10-20 percent, clear expectation from the Commission that the utilities would adjust their procurement practices to address departing load, and clear obligations to minimize costs under Standard of Conduct No. 4.

37. CCA customers in PG&E's service territory bear cost responsibility for procurement made prior to their departures even though their departure did not create excess utility supply.

38. Procurement commitments by the utilities that are made with knowledge of imminent CCA departure(s), and which knowledge does not lead to changes in the utilities' procurement plans, are not eligible for cost recovery from those departing load customers.

39. The Joint Utilities, in Phase 2 of this proceeding, must identify utility procurement commitments that were made with knowledge of CCA departing load and with no accompanying change to the procurement plans to account for those departures.

40. Deficient utility forecasting of departing CCA load causes CCA customers to pay for both the un-attributable above-market costs incurred by the utilities and the costs incurred by the CCA as the customers' new load serving entity.

41. Marin Clean Energy customers are uniquely vulnerable to PG&E's deficient forecasting because Marin Clean Energy's customers also face high above-market cost for early RPS resources procured by Marin Clean Energy for its customers.

42. A probabilistic approach to CCA load departures coupled with a scenario-based assessment of potential long-term load departures would appropriately capture future CCA load departures and mitigate the potential for excess utility resources and increased costs.

Proposed Modifications to Conclusions of Law

26*. Public Utilities Code Section 366.2(f)(2) provides that CCA customers are only responsible for paying the above-market unavoidable costs attributable to those customers.*

27. Public Utilities Code Section 365.2 prohibits cost increases for CCA customers due to allocation of costs not incurred on behalf of the departing load.

28. Costs are not attributable to CCA departing load under 366.2(f)(2) and 365.2 if a utility has reasonable evidence of CCA departures and fails to modify its procurement accordingly.

29. The Joint Utilities' historical forecasting practices unreasonably ignored early CCA load departures in violation of Commission directive and Standard of Conduct No. 4.

30. The PG&E's decision to not adjust their portfolios to account for CCA load departures until such departures reached 10-20% of bundled load violates Public Utilities Code Section 365.2 by leading to increased costs for CCA customers.

31. Public Utilities Code Section 366.2(f)(2) and 365.2 require that Marin Clean Energy's 2010 vintage be exempt from paying above-market costs associated with PG&E RPS procurement in 2010.

32. Public Utilities Code Section 366.2(f)(2) and 365.2 prohibit allocation of costs to departing load after that load has departed.

33. PG&E's decision to not adjust its procurement in 2010 in light of Marin Clean Energy's forecast departures and actual launch resulted in a cost shift to Marin Clean Energy's 2010 vintage.

34. PG&E's decision to not adjust its procurement in 2010 in light of Marin Clean Energy's imminent departure and actual launch in 2010 resulted in an illegal cost shift to Marin Clean Energy's 2010 vintage.

35. California Public Utilities Code Sections 366.2(f)(2) and 354.2 require PG&E to stop charging Marin Clean Energy's 2010 vintage for costs associated with PG&E's RPS procurement in 2010.

36. A probabilistic approach to CCA load departures coupled with a scenario-based assessment of potential long-term load departures would appropriately capture future CCA load departures and mitigate the potential for excess utility resources and increased costs in satisfaction of California Public Utilities Code Sections 366.2(f)(2) and 354.2 .

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)

MARIN CLEAN ENERGY'S COMMENTS ON THE ALTERNATE PROPOSED DECISION OF COMMISSIONER CARLA J. PETERMAN TO THE PROPOSED DECISION OF ADMINISTRATIVE LAW JUDGE STEPHEN C. ROSCOW MODIFYING THE POWER CHARGE INDIFFERENCE ADJUSTMENT METHODOLOGY

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Pursuant to the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Rule 14.3, Marin Clean Energy ("MCE") submits the following comments in response to the *Alternate Proposed Decision of Commissioner Carla J. Peterman to the Proposed Decision of Administrative Law Judge Stephen C. Roscow Modifying the Power Charge Indifference Adjustment Methodology* ("Alternate Proposed Decision" or "APD"), issued August 14, 2018.

INTRODUCTION

MCE appreciates the opportunity to provide comments on the Alternate Proposed Decision. Unfortunately, the APD fails to hold the Investor-Owned Utilities ("IOU") responsible for imprudent management of their generation portfolios and provides little incentive for the IOUs to reduce above-market costs or correct improper allocation of costs to CCA customers due to deficient IOU forecasting practices.

MCE limits its comments to the discrete issue of IOU forecasting as it relates to determination of CCA customers' cost responsibility for executed utility power contracts paid through the Power Charge Indifference Adjustment ("PCIA"). MCE supports the positions put forth by the California Community Choice Association ("CalCCA") through its testimony, hearings, briefing, and comments in the instant phase on this issue. MCE supports the positions taken in this proceeding by CalCCA on all issues not addressed in these comments.

MCE agrees that the Commission has "acted in this proceeding to determine with unprecedented precision the nature of the costs incurred by the Joint Utilities . . . ."[1] However, given the APD's conclusions on Legacy Utility Owned Generation ("UOG"), post-2002 UOG, IOU portfolio valuation, and the APD's silence on the IOUs' deficient forecasting, the Commission cannot conclude that the revised PCIA methodology "only include[s] legitimately unavoidable costs and account[s] for the IOUs' responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize above-market costs."[2] The IOUs' portfolio mismanagement and demonstrated rejection of the Commission's forecasting directives resulted precisely in *avoidable* costs and *mismanaged* portfolios that *increased* above-market costs assigned to CCA customers. Failure to acknowledge this jeopardizes the legal and factual integrity of the Alternate Proposed Decision and ultimately frustrates Phase II's "promise of meaningful progress toward reducing the levels of above-market costs going forward."[3]

MCE respectfully requests the Commission address deficient utility forecasting practices in the instant phase. CalCCA demonstrated that the IOUs' historical forecasting practices violated the indifference principle by assigning un-attributable and avoidable costs to CCA customers. In Pacific Gas and Electric Company's ("PG&E") case, CalCCA demonstrated that PG&E made resource commitments in 2010 for customers it knew were going to depart bundled utility service. Any resources acquired with knowledge of departure could not reasonably be expected to serve

[1] Alternate Proposed Decision at p. 99.
[2] *Id*.
[3] *Id*.

and benefit that departing CCA load; benefits flowed to PG&E's bundled load and aided achievement of PG&E's Renewable Portfolio Standard ("RPS") targets. These procurement costs in 2010 are both avoidable and un-attributable to MCE's 2010 vintage--continuing to charge MCE's or other CCAs' customers for costs accrued in the face of imminent CCA departing load undermines indifference and violates statutory requirements.

To cure the APD's legal and factual errors surrounding IOU forecasting, MCE respectfully requests the following revisions:

- The Commission should acknowledge the IOUs' demonstrated failure to forecast and account for CCA departing load--the demonstrated deficiencies in the IOUs' historical CCA forecasting practices have created avoidable cost responsibility for CCA customers for contracts that cannot reasonably be attributed to those customers.
- The Commission should acknowledge that the IOUs' historical failure to forecast violates the indifference principle.
- The Commission should direct the utilities in Phase II to identify, with precision, the procurement commitments that have been attributed to CCA customers, but were made with knowledge of CCA departing load and with no accompanying change to the procurement plans to account for those departures. CCA departing load customers should be exempt from paying any such costs.
- The Commission should reinforce past Commission directives and order that the IOUs shall not attribute costs to departing load CCA customers for resources procured once an IOU has reasonable evidence of departure and the IOU fails to modify its procurement to account for the departure.

- The Commission should protect CCA customers from deficient IOU forecasting and prohibit the IOUs from allocating uneconomic and avoidable costs for contracts executed after CCA load departs bundled utility service.
- The Commission should direct the IOUs to use a probabilistic approach to forecast CCA departing load and file a scenario-based assessment of potential long-term load departures to appropriately capture future CCA load departures and mitigate the potential for excess utility resources and increased costs.[4]
- Going forward, the Commission should direct that CCA customers are exempt from cost responsibility for IOU contracts executed in a certain year up to the amount of departing load forecast for that year because such costs are avoidable by the IOUs if they properly forecast their load.

DISCUSSION

The APD commits legal and factual error by failing to address PG&E's, Southern California Edison Company's ("SCE"), and San Diego Gas and Electric Company's ("SDG&E") (collectively "Joint Utilities") forecasting practices. The APD draws no conclusions about the necessity of proper utility forecasting. Nor does the APD acknowledge that CalCCA demonstrated that the IOUs' refusal to forecast and account for CCA departing load violated the indifference principle and unlawfully attributed costs to CCA customers for resources that could not be expected to serve that load. The APD's omissions facilitate and continue an impermissible, avoidable, and correctable cost shift to CCA customers. This cost shift primarily affects earlier

[4] *See* Opening Brief of the California Community Choice Association (Public Version), filed June 1, 2018 ("CalCCA Brief") at pp. 102-03.

vintage CCA customers, such as those enrolled in MCE, but this failure to forecast has lingering unlawful cost shifting effects for all CCA departing load.

The APD is clear that this proceeding should "prevent cost increases for CCA customers as a result of an allocation of costs that were not incurred on behalf of the departing load[.]"[5] Through hearings and briefing, CalCCA demonstrated a PG&E strategy that created precisely this prohibited result.[6] There were cost shifts to MCE customers resulting from early PG&E RPS contract costs being allocated to MCE customers despite PG&E's substantial knowledge of MCE's imminent and actual departing load. The Commission must formally acknowledge that PG&E's past deliberate failures to forecast and account for CCA departing load in its procurement and cost allocations have unlawfully assigned costs to CCA customers, otherwise the APD retains errors of fact. The Commission must also eliminate cost shifts due to the IOUs' historical forecasting practices for CCA customers and ensure symmetrical and lawful application of the indifference principle to both bundled and CCA customers going forward, otherwise the APD commits an error of law.

A. The APD Should Be Revised to Prohibit the Joint Utilities from Allocating Above-Market Costs for Contracts Executed Once the IOU Has Reasonable Notice of Departure and Fails to Adjust Its Procurement to Account for the Anticipated Departures.

According to statute, departing load CCA customers are only responsible for unavoidable above-market costs attributable to those customers.[7] Moreover, CCA customers' costs cannot increase due to allocation of costs not incurred on their behalf.[8] A cost can be reasonably attributable to customers only if a utility procures a resource to serve those customers.

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[5] Alternate Proposed Decision at p.11; *see also* Pub. Util. Code Section 365.2.
[6] CalCCA Brief at pp. 99-103.
[7] Pub. Util. Code Section 366.2(f)(2).
[8] Pub. Util. Code Section 365.2.

Since 2004, the Commission has expected the utilities to forecast departing load to mitigate the risk of unnecessary resource commitments that may be stranded due to anticipated departing load. The Commission has been clear that the utilities should "us[e] available information to forecast customer demand and should incorporate CCA load losses into their planning efforts, just as they would include any other forecast variable related to expected changes in supply or demand."[9] The APD also cites the Commission's early directive that the utilities "acknowledge potential CCA departing load and identify which city and/or county has expressed intent to pursue aggregation, including MW estimates of this departing load, in future procurement plans."[10] CalCCA demonstrated that the IOUs ignored these directives. In particular, PG&E departed from statutory and Commission directives by allocating costs to MCE customers for resources PG&E had every reason to conclude would not serve those customers. PG&E's conduct created avoidable and unreasonable costs for CCA customers for which they are not responsible.

1. SCE and PG&E Ignored CCA Departing Load in Their Procurement Planning Leading to Avoidable and Un-Attributable Costs Being Shifted to CCA Customers.

The Commission is tasked with ensuring 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."[11] At hearings, SCE and PG&E confirmed that they effectively disregarded the Commission's guidance in Decision 04-12-046 and Decision 04-12-048 by choosing to establish a narrowly defined threshold for forecasting departing load.[12] The IOUs' unlawful failure to forecast effectively justified utility procurement on behalf of departing load for as long as possible,

[9] Decision 04-12-046 at p. 30.
[10] Decision 04-12-048, Ordering Paragraph 9 at p. 239.
[11] Pub. Util. Code Section 365.2.
[12] *See* 4 Tr. 809: 20-810: 3 (Cushnie); 4 Tr. 813: 9-10 (Lawlor); 4 Tr. 817: 13-820:16 (Lawlor); 821: 26-822:3 (Lawlor); 5 Tr. 857: 13-21 (Lawlor); *see also* CalCCA Brief at pp. 98-99.

even though all indications were that load would depart.[13] Particularly in the early years of CCA departure, this deviation from Commission directive allowed the utilities to completely ignore the potential for dramatic increases in CCA customer departure. As a result, IOU forecasts failed to appropriately inform their long-term procurement contracting, which has affected cost allocation for 20-30 year financial commitments made by the utilities.[14] In fact, it was not until after Decision 14-02-040 that the utilities started forecasting CCA departing load in their bundled procurement plans due to a Commission order. The fact that this order came four years after MCE began serving customers demonstrates an unlawful cost shift to CCA customers for *avoidable* costs *not* attributable to their departure but instead due to PG&E's negligence and deliberate failure to forecast.

2. PG&E Willfully Ignored MCE's Departing Load in 2010 and Failed to Adjust Its Portfolio Causing Illegal Allocation of Cost Responsibility to MCE Customers for Avoidable Costs Not Attributable to MCE Customers.

With respect to MCE's launch in 2010, the record establishes that PG&E failed to follow even its own narrowly defined threshold for CCA forecasting. The record demonstrates that PG&E was aware of MCE's (then Marin Energy Authority) intention to launch in 2010 via MCE's submitted and CPUC-certified implementation plan.[15] Indeed, PG&E was certainly well-aware of the formation of MCE before MCE submitted its implementation plan. This is demonstrated by PG&E's contribution of $44 million in funding for the creation and promotion of Proposition 16, a statewide ballot initiative aimed to prevent CCA formation and that ultimately lead to legislative and Commission intervention to constrain PG&E's egregious and obstructive behavior.[16]

[13] 4 Tr. 817: 13-820: 16 (Lawlor); 821: 26-822:3 (Lawlor); 5 Tr. 857: 13-21 (Lawlor).
[14] *See* CalCCA Brief at pp. 97-103.
[15] 4 Tr. 817: 13-820: 16 (Lawlor); 821: 26-822:3 (Lawlor); 5 Tr. 857:13-17 (Lawlor); 5 Tr. 857:18-21 (Lawlor); *see also* CalCCA Brief at p. 99.
[16] *See* Senate Bill 790 (Stats. 2011, Ch. 599; *see also* Decision 12-12-036.

Notwithstanding PG&E's anti-CCA campaign, MCE's implementation plan indicated load in 2010, including forecast load growth through 2019, and indications of active negotiations for long-term power contracts to serve this load.[17] Yet, PG&E proceeded to execute contracts in 2010 (representing approximately 1.7 GW of capacity)--all of which were executed after MCE submitted its implementation plan, some of which were executed after certification of MCE's implementation plan by the Commission, and approximately 600 MW of which was executed after MCE launched.[18]

Despite clear knowledge of MCE's launch, forecasted long-term load growth, and MCE's 2010 long-term contracting efforts,[19] PG&E continued to assign cost responsibility to MCE's 2010 vintage for this 2010 procurement.[20] In this particular instance, cost responsibility is not due to PG&E's deficient forecasting, it is due to PG&E's deliberate tactic to ignore both forecasted *and* actual CCA departures and failure to adjust its portfolio and costs accordingly.[21] The resources secured in 2010 should never have been assumed to serve MCE's 2010 vintage because PG&E was keenly aware that load would be departing or had already departed. Therefore, the above-market costs allocated to MCE's 2010 vintage are certainly not "unavoidable" as required by statute. The Commission must acknowledge and correct the illegal and persistent allocation of costs to MCE customers that resulted from PG&E's deliberate ignorance of all notice of MCE's imminent and actual departure.

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[17] 4 Tr. 820: 11-16 (Lawlor).
[18] *See* Exh. CalCCA-123, Maximum Contract Capacity; *see also* Exh. CalCCA-123, PG&E 2010 Contract Execution Dates from Attachment 10 ALJ Requested Data Matrix. .
[19] 4 Tr. 819: 1 – 822:3 (Lawlor).
[20] *See* CalCCA Brief at 98-99.
[21] *See id*. at pp. 100-01.

3. MCE's and Other CCAs' Departing Load Experience Cost Shifts Resulting from Deficient IOU Forecasting Because They Bear Cost Responsibility for Contracts Executed by their CCA in Addition to Avoidable, Un-Attributable Above-Market Costs Allocated to Them by the IOUs.

MCE and other CCA customers retain cost responsibility for PG&E's avoidable 2010 above-market procurement costs to this day.[22] The IOUs' "narrowly-defined departing load forecasting approach completely missed the potential for the dramatic increases in departure that [ ] are being experienced now."[23] This IOU strategy of assuming minimal to no CCA load departure has amplified rate impacts on CCA customers because CCA customers are paying twice; they are responsible for IOU above-market procurement costs in addition to the costs associated with their CCA's procurement. In particular, MCE's early vintages until D.14-02-040 are not only allocated above-market costs for those PG&E resources secured with substantial notice of MCE's departure, but they are also bearing duplicative cost responsibility for procurement MCE was obligated to make on behalf of its customers as their new Load Serving Entity. Moreover, many of MCE's early contractual obligations are subject to the same dramatic above-market cost concerns faced by the Joint Utilities. No widespread socialization of these above-market costs is possible for these CCA customers. Forcing CCA customers to pay twice for above-market resources because of negligent utility planning violates the indifference principle. The APD commits legal and factual error by failing to acknowledge and resolve this unjust and unreasonable cost shift to CCA customers. Unless and until this is resolved, the full potential of this phase of the proceeding is unfulfilled: unprecedented determination of the nature of the costs incurred by the Joint Utilities.

[22] *See* Exh. CalCCA-123, PG&E 2010 Contract Execution Dates from Attachment 10 ALJ Requested Data Matrix.
[23] CalCCA Brief at pp. 98-99.

4. CCA Departing Load Customers Subsidizing PG&E's RPS Targets for Its Bundled Load Creates an Illegal Cost Shift to CCA Customers.

CCA customers' PCIA cost responsibility must be reduced "by the value of any benefits that remain with the bundled customers . . . ."[24] Most astonishing, given the emphasis in this proceeding on attaining the indifference principle, PG&E defended its historical forecasting and admitted that it would not have made any procurement decisions based on the anticipated CCA load departure MCE represented.[25] In fact, PG&E admitted that it would take load departures of up to 10-20 percent before PG&E adjusted it procurement practices.[26] Continuing to charge CCA customers for resources an IOU has reason to believe will not serve those customers and further failing to adjust procurement and cost allocations accordingly violates indifference.

With specific reference to MCE in 2010, PG&E indicated that its 2010 executed contracts were "purchased . . . knowing that [PG&E] needed to meet its RPS targets on a total portfolio basis . . . We don't manage to a departure. We had an open need, and we manage it in a bundled way."[27] MCE's 2010 and future anticipated departures should have reduced that "open need". MCE's 2010 vintage should never have been attributed costs or benefits from PG&E's procurement in that year because PG&E had every reason to know and plan for MCE's departure.[28] Moreover, the fact that no amount of CCA departures up to 10-20 percent would be cause to change procurement practices strongly implies bundled customers retained substantial benefit from departing CCA load--either PG&E continues to hold all of its resources acquired prior 10-20% CCA departure for the benefit of bundled customers or PG&E failed to act in accordance with state law and Commission policy

[24] Pub. Util. Code Section 366.2(g).
[25] 4 Tr. 822: 24-823: 20 (Lawlor); 5 Tr. 853:25-854:1 (Lawlor).
[26] 1 Tr. 37:17-21 (Wan).
[27] 4 Tr. 822: 24-823: 20 (Lawlor).
[28] CalCCA Brief at pp. 99-100.

to forecast departing load and manage its portfolio accordingly. Both scenarios violate indifference.

The Commission's final decision in this phase must acknowledge this unlawful practice and commit to resolving the resulting cost shifts to CCA customers due to IOU, and particularly PG&E's, forecasting practices in Phase II. Failure to do so results in both an error of fact and an error of law because it results in an asymmetrical application of the indifference principle. CCA customers reasonably anticipated to depart are forced to subsidize PG&E's efforts to achieve its RPS targets, while the procurement benefits flow to bundled customers. CCA customers should not bear the cost responsibility for these actions.

B. The Commission Should Direct the Joint Utilities to Use a Probabilistic Approach to Forecasting CCA Departing Load and Require the IOUs to Prepare and File Scenario-Based Assessment of Long-Term CCA Departing Load.

The APD must direct the Joint Utilities to properly forecast CCA departing load and alter their portfolio management practices accordingly using a probabilistic forecasting approach. Failure to do so is factual and legal error because it would ignore reasonable and achievable steps towards indifference and fail to eliminate future cost shifting due to poor IOU forecasting. Commission reinforcement of Decision 14-04-020 on this issue is crucial given estimates in this proceeding of potential load departure of up to 85%. The proceeding has demonstrated that reliance on the Binding Notice of Intent does little to mitigate cost shifting, particularly in a situation where the Joint Utilities are long on their RPS resources. The Commission should direct in the instant phase that the Joint Utilities return to a "common sense" forecasting practice as the Commission articulated it in D.03-04-030.[29] The utilities already use such an approach for their large industrial and agricultural customers.[30] The same practice should apply to CCA departing load.

To complement and facilitate more aggressive IOU forecasting of CCA departing load, the Commission should direct the IOUs to file scenario-based assessments of the potential long-term range of future load departures.[31] As part of this filing, the IOUs should demonstrate that their resource plans are able to adapt to changing supply obligations due to future load departure scenarios.[32] The Commission is obligated to take active steps to uphold indifference. Failure to revise the APD and direct the IOUs to adopt more aggressive forecasting of CCA departing load will encourage and facilitate additional illegal cost shifts to CCA customers.

C. The Commission Should Direct that CCA Customers Be Exempt from Contracts Executed in a Certain Year up to the Amount of Departing Load Forecast for that Year.

Going forward, the Commission should take steps to ensure that forecasted departing load is not attributed cost responsibility for contracts executed in a certain year up the amount of departing load forecast for that year.[33] Assigning cost responsibility for such contracts violates indifference because such costs are avoidable if the IOUs are properly forecasting their load. If the utility excludes an amount of departing load in establishing its procurement plan using the probabilistic forecasting approach advocated for by CalCCA, any procurement under the procurement plan cannot be mischaracterized as attributable to that departing load, consistent with D.03-04-030. Moreover, exclusion of that CCA departing load from cost responsibility would mitigate duplicative procurement and costs that would be borne by CCA customers.

[29] *Id*. at p.102.
[30] *Id*.
[31] *Id*. at p. 103.
[32] *Id*.
[33] *Id*.

CONCLUSION

MCE thanks Commissioner Peterman and ALJ Roscow for their thoughtful consideration of these comments.

Respectfully submitted,

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APPENDIX

Pursuant to Rule 14.3(b) of the Commission's Rules of Practice and Procedure, Marin Clean Energy offers the following index of proposed changes to the Findings of Fact and Conclusions of Law to the *Alternate Proposed Decision of Commissioner Carla J. Peterman to the Proposed Decision of Administrative Law Judge Stephen C. Roscow Modifying the Power Charge Indifference Adjustment Methodology*. MCE's proposed revisions appear in italics.

Proposed Modifications to Findings of Fact

29. Proper utility forecasting of CCA departing load is necessary to ensure indifference.

30. Since 2004, the Commission has directed the Joint Utilities to forecast CCA departing load using all available information and modify their respective loads accordingly to mitigate excess procurement and costs.

31. The Joint Utilities' historical forecasting practices did not allow for forecasting of large scale CCA departing load.

32. The Joint Utilities' historical forecasting practices departed from prior Commission direction, which has created avoidable above-market costs that are not be attributable to CCA departing load customers.

33. PG&E failed to acknowledge all reasonable and available information regarding Marin Clean Energy's launch in 2010 in its procurement planning.

34. PG&E was well aware of Marin Clean Energy's likely departure in advance of Marin Clean Energy filing its implementation plan due to PG&E's aggressive anti-CCA campaign activities, which ultimately lead to passage of Senate Bill 790 and lead to the Commission's adoption of the Code of Conduct.

35. PG&E's failure to acknowledge all reasonable and available information regarding Marin Clean Energy's launch in 2010 in its procurement planning resulted in Marin Clean Energy customers being attributed costs for procurement in 2010 that could not have reasonably been expected to serve that load.

36. PG&E has done nothing to adjust its portfolio following the departure of CCA load until very recently, despite far more load departure than 10-20 percent, clear expectation from the Commission that the utilities would adjust their procurement practices to address departing load, and clear obligations to minimize costs under Standard of Conduct No. 4.

37. CCA customers in PG&E's service territory bear cost responsibility for procurement made prior to their departures even though their departure did not create excess utility supply.

38. Procurement commitments by the utilities that are made with knowledge of imminent CCA departure(s), and which knowledge does not lead to changes in the utilities' procurement plans, are not eligible for cost recovery from those departing load customers.

39. The Joint Utilities, in Phase 2 of this proceeding, must identify utility procurement commitments that were made with knowledge of CCA departing load and with no accompanying change to the procurement plans to account for those departures.

40. Deficient utility forecasting of departing CCA load causes CCA customers to pay for both the un-attributable above-market costs incurred by the utilities and the costs incurred by the CCA as the customers' new load serving entity.

41. Marin Clean Energy customers are uniquely vulnerable to PG&E's deficient forecasting because Marin Clean Energy's customers also face high above-market cost for early RPS resources procured by Marin Clean Energy for its customers.

42. A probabilistic approach to CCA load departures coupled with a scenario-based assessment of potential long-term load departures would appropriately capture future CCA load departures and mitigate the potential for excess utility resources and increased costs.

Proposed Modifications to Conclusions of Law

26. *Public Utilities Code Section 366.2(f)(2) provides that CCA customers are only responsible for paying the above-market unavoidable costs attributable to those customers.*

27. Public Utilities Code Section 365.2 prohibits cost increases for CCA customers due to allocation of costs not incurred on behalf of the departing load.

28. Costs are not attributable to CCA departing load under 366.2(f)(2) and 365.2 if a utility has reasonable evidence of CCA departures and fails to modify its procurement accordingly.

29. The Joint Utilities' historical forecasting practices unreasonably ignored early CCA load departures in violation of Commission directive and Standard of Conduct No. 4.

30. The PG&E's decision to not adjust their portfolios to account for CCA load departures until such departures reached 10-20% of bundled load violates Public Utilities Code Section 365.2 by leading to increased costs for CCA customers.

31. Public Utilities Code Section 366.2(f)(2) and 365.2 require that Marin Clean Energy's 2010 vintage be exempt from paying above-market costs associated with PG&E RPS procurement in 2010.

32. Public Utilities Code Section 366.2(f)(2) and 365.2 prohibit allocation of costs to departing load after that load has departed.

33. PG&E's decision to not adjust its procurement in 2010 in light of Marin Clean Energy's forecast departures and actual launch resulted in a cost shift to Marin Clean Energy's 2010 vintage.

34. PG&E's decision to not adjust its procurement in 2010 in light of Marin Clean Energy's imminent departure and actual launch in 2010 resulted in an illegal cost shift to Marin Clean Energy's 2010 vintage.

35. Utility shareholders, not bundled utility customers or CCA customers, should be responsible for above-market, avoidable costs that result from portfolio mismanagement, including stranded costs that result from a utilities' failure to forecast reasonably.

36. California Public Utilities Code Sections 366.2(f)(2) and 354.2 require PG&E to stop charging Marin Clean Energy's 2010 vintage for costs associated with PG&E's RPS procurement in 2010.

37. A probabilistic approach to CCA load departures coupled with a scenario-based assessment of potential long-term load departures would appropriately capture future CCA load departures and mitigate the potential for excess utility resources and increased costs in satisfaction of California Public Utilities Code Sections 366.2(f)(2) and 354.2 .

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Pursuant to the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Rule 14.3 and the *Email Ruling Modifying the Due Date for Consolidated Reply Comments on the PD and ADP*, issued by Administrative Law Judge ("ALJ") Roscow on September 7, 2018, Marin Clean Energy ("MCE") respectfully submits the following reply to comments on the *Proposed Decision Modifying the Power Charge Indifference Adjustment Methodology* ("Proposed Decision" or "PD") and the *Alternate Proposed Decision of Commissioner Carla J. Peterman to the Proposed Decision of Administrative Law Judge Stephen C. Roscow Modifying the Power Charge Indifference Adjustment Methodology* ("Alternate Proposed Decision" or "APD"), issued August 1, 2018 and August 14, 2018, respectively.

INTRODUCTION

MCE appreciates the opportunity to provide reply comments on both the Proposed Decision and Alternate Proposed Decision. MCE's comments address misrepresentations of law and fact contained in the comments of Pacific Gas and Electric Company ("PG&E"), San Diego

Gas and Electric Company and Southern California Edison Company (collectively "Joint Utilities") on the Alternate Proposed Decision relating to utility forecasting of departing community choice aggregator ("CCA") load.

As demonstrated in the record, CCA customers are currently bearing avoidable IOU costs, contrary to statute. There is a demonstrated cost-shift that is imposing a range of utility and bundled customer costs on CCA customers. As such, a range of adjustments are needed to address the multiple unlawful cost shifts. However, MCE will focus solely on two issues in this filing related to inappropriate cost shifts. MCE encourages the Commission to look holistically at the range of impacts together in determining a fair outcome for all parties.

MCE agrees with the Joint Utilities that the APD and PD should be revised to include improved accuracy of departing load forecasting as an issue in Phase II of the instant proceeding. In addition, to appropriately frame Phase II's forecasting discussion, the Commission must acknowledge the utilities' past forecasting failures that the Joint Utilities obscure in their opening comments on the APD. The Joint Utilities', particularly PG&E's, failure to follow Commission directives regarding forecasting of CCA departing load resulted in over-procurement and avoidable costs that have been impermissibly allocated to CCA customers, which is contrary to statute.[1] As part of Phase II, the Commission should commit to identify and resolve cost-shifts to CCA customers resulting from the Joint Utilities' deliberate failure to forecast CCA departing load, particularly in the early years of CCA formation, which has a specific impact on MCE's early vintage customers. Including these avoidable costs in the Power Charge Indifference Adjustment ("PCIA") for MCE and other CCA customers exacerbates the already material cost shift caused

[1] Pub. Util. Code Sections 365.2 and 366.2(f)(2)-(g).

by the PD's and APD's benchmarking errors emphasized by the California Community Choice Association ("CalCCA") and other parties.

DISCUSSION

A. The Joint Utilities Should Not Be Allowed To Avoid Their Long-Standing Requirement to Forecast Departing Load and Their Responsibility in Failing to Follow Such Commission Directives.

The Joint Utilities assert that they should not be responsible for "divining CCA departure plans with perfect precision . . . ."[2] Instead, they argue the responsibility should fall on the CCAs. While MCE agrees there are ways to improve forecasting, including improved communication between utilities and CCAs, the Joint Utilities' position ignores the fact that they are, and have been, required to forecast departing load pursuant to long-standing Commission directives most recently reinforced in Decision ("D") 14-02-040.[3] The Commission has directed use of a range of information and strategies to forecast CCA departing load, including (1) a "common sense" approach,[4] (2) use of all "available information to forecast customer demand and . . . incorporate CCA load losses into their planning efforts, just as [the utilities] would include any other forecast variable related to expected changes in supply or demand"[5], and (3) a Binding Notice of Intent ("BNI") from CCAs. The record in this proceeding demonstrates the Joint Utilities, particularly PG&E, simply chose not to follow such directives with respect to early CCA formation and continued to procure up to 10-20% load departure without portfolio modifications.[6] Short of near-

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[2] *Comments of Pacific Gas and Electric Company, San Diego Gas and Electric Company and Southern California Edison Company on the Alternate Proposed Decision Modifying the Power Charge Indifference Adjustment Methodology* ("Opening Comments"), filed September 6, 2018, at p. 20.
[3] Decision 14-02-040, Ordering Paragraph 1 at pp. 74-75; Decision 04-12-046 at p. 30; Decision 04-12-048, Ordering Paragraph 9 at p. 239; Decision 03-04-030 at p. 54.
[4] D.03-04-030 at p. 54.
[5] Decision 04-12-046 at p. 30.
[6] *See* 1 Tr. 37:17-21 (Wan); 4 Tr. 809: 20-810: 3 (Cushnie); 4 Tr. 813: 9-10 (Lawlor); 4 Tr. 817: 13-820:16 (Lawlor); 821: 26-822:3 (Lawlor); 4 Tr. 822: 24-823: 20 (Lawlor); 5 Tr. 857: 13-21 (Lawlor); *see also* CalCCA Brief at pp. 98-99.

certainty of departing load via a BNI, the utilities ignored imminent and actual CCA load departures and the potential for dramatic increases in CCA load departure. Consequently, utility forecasts failed to inform their long-term procurement contracting leading to over-procurement and avoidable costs passed through to CCA customers.[7]

The Joint Utilities' comments are silent on this issue. The fact that the utilities, especially PG&E, did not start forecasting CCA departing load until 2014[8] – four years after MCE launched – demonstrates an unlawful cost shift to CCA customers for *avoidable* costs *not* attributable to their departure but instead due to PG&E's deliberate failure to forecast. MCE customers that began service during this four-year period are currently paying, and will continue paying for IOU purchases made after their departure for many years into the future. It is therefore critical for the Commission to identify and resolve such cost shifts to avoid further violations of Pub. Util. Code Sections 365.2 and 366.2(f)(2)-(g).

The Commission should not allow the Joint Utilities to rely on forecasting uncertainty to justify their failure to forecast early CCA departing load. Again, the Joint Utilities' comments indicate that CalCCA inappropriately "places the burden of correctly forecasting departing load *entirely* on the Joint Utilities . . . ."[9] Whether the Joint Utilities disagreed with the long-standing Commission policy guidance, or found that guidance difficult to comply with, is immaterial. In fact, all Load Serving Entities are required to forecast their load using less than certain and complete information. Unlike the utilities, though, CCAs have no feasible mechanism for cost recovery for unanticipated costs that result from imperfect forecasts. The Joint Utilities' complaint of uncertainty surrounding departing load does not excuse them from complying with long-

[7] *See* CalCCA Brief at pp. 97-103.
[8] *See* Decision 14-02-040.
[9] Opening Comments at p. 21.

standing Commission guidance that explicitly directed them to forecast departing load using something less than absolute certainty.

The Commission should not permit the Joint Utilities to evade responsibly for their historical deliberate and deficient forecasting. Instead, the Commission should use Phase II to identify (1) the extent to which these past utility forecasting decisions resulted in over-procurement and avoidable above-market costs being assigned to CCA customers through the PCIA; and (2) reasonable ways for the utilities to obtain the information they need to adequately forecast future CCA departing load and mitigate future forecasting inaccuracies.

B. The Joint Utilities' Comments Contradict Their Actions and Admissions in This Proceeding.

The Joint Utilities' comments suggest CCAs' failure to provide actionable and timely load departure information is a significant factor in driving over-procurement and cost-shifts to bundled customers. Specifically, the Joint Utilities claim that "[t]he current protocol allows CCAs to avoid responsibility for the accuracy of the [load departure] information they provide . . . This creates the potential for unnecessary procurement by the Joint Utilities and impermissible cost-shifting."[10] This assertion, however, is largely belied by PG&E's own admission that it does not manage its portfolio to departures.[11] The Joint Utilities' position is further undermined by PG&E's admission that departures short of 10-20% of bundled load result in no portfolio modifications.[12] Taken together, the fact that no amount of CCA departures up to 10-20% would be cause to change procurement practices strongly indicates bundled customers retained substantial benefit from early vintage CCA departures. Consequently, these CCA customers are bearing inappropriate cost

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[10] Opening Comments at p. 21-2.
[11] 4 Tr. 822: 24-823: 20 (Lawlor).
[12] 1 Tr. 37:17-21 (Wan).

responsibility in violation of Pub. Util. Code Section 366.2(f)-(g). Either PG&E continues to hold all of its resources acquired prior 10-20% departure for the benefit of bundled customers or PG&E failed to act in accordance with state law and Commission policy to forecast departing load and manage its portfolio accordingly. Both scenarios violate indifference; both scenarios contradict the Joint Utilities' position that deficient load departure information provided by CCAs drives over-procurement and cost-shifts. On the contrary, the record demonstrates that the utilities' failure to forecast CCA departing load and adjust their portfolios accordingly was a significant contributing factor to over-procurement and cost shifts to CCA customers. The Commission must take steps in Phase II to examine the effects of these decisions and resolve resulting cost-shifts to CCA customers.

CONCLUSION

MCE thanks Commissioner Peterman and ALJ Roscow for their thoughtful consideration of these reply comments.

Respectfully submitted,

/s/ Nathaniel Malcolm

/s/ Shalini Swaroop

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September 13, 2018

Marin Clean Energy ("MCE")
Response to California Public Utilities Commission ("CPUC") June 28, 2018 Data Request Regarding Statutory Reporting Requirements Pursuant to Public Utilities Code Section 913.4

GENERAL STATEMENT

On June 28, 2018, the CPUC issued a data request to MCE for certain information regarding MCE's recruitment, hiring, training, and procurement practices "to evaluate the progress of the state's load-serving entities in complying with the renewables portfolio standard (RPS) program" ("Data Request" or "Request"). The CPUC cited California Public Utilities Code ("Code") Section 913.4(f) as the statutory authority for the Data Request and referenced that provision's reporting requirements for electrical corporations.

The CPUC lacks the authority under Code Section 913.4(f) to require MCE to submit the requested data. There is no basis for the CPUC to conclude that Code Section 399.12(j) extends Code Section 913.4(f) to apply to community choice aggregators ("CCA"). Code Section 913.4(f) explicitly applies to electrical corporations. MCE is not an electrical corporation; it is a public agency subject to different sections of the Code and subject to oversight by its publicly elected Board of Directors. Nonetheless, MCE is voluntarily responding to the CPUC's request to the extent MCE has responsive data.

The CPUC's Data Request also seeks information concerning certain "Women, Minority, and Disabled Veteran ("WMDV") employees and business enterprises." Under California Proposition 209, Cal. Const. Art. 1, Section 31(a), "[t]he State shall not discriminate against, or grant preferential treatment to, any individual or group on the basis of race, sex, color, ethnicity, or national origin in the operation of public employment, public education, or public contracting." Proposition 209 defines "the State" to include "any city, county, city and county . . . or any other political subdivision or governmental instrumentality of or within the State."

As a public agency, MCE is subject to Proposition 209. MCE does not use race, sex, color, ethnicity, or national origin in its recruitment, outreach, hiring, training, procurement, or contracting decisions or practices for any purpose or in any manner prohibited by Proposition 209. To the extent MCE provides responses or data about characteristics of any individual or group articulated in Proposition 209, MCE has collected that information solely for legally permissible purposes.

Nothing in MCE's response to this Data Request should be construed as prejudicing or waiving MCE's right to produce and provide additional documentary evidence or responses based on information, evidence, or analysis hereafter obtained or evaluated. MCE's responses are made subject to inadvertent or undiscovered errors and are limited by records and information still in existence and/or presently recollected and thus far discovered in the course of preparing this response. MCE reserves the right to update and/or supplement the responses provided herein if and when additional evidence or information, which is responsive to the Data Request, becomes available and at any time if it appears that inadvertent errors or omissions have been made.

These responses are made without intending to waive or relinquish MCE's rights to take the following actions:

1. Raise all questions regarding legality, relevancy, materiality, privilege, or admissibility as evidence for any purpose as to any documents identified or produced in response to this Data Request, which may arise in any proceeding, any litigation related to the provided responses, or any other action related to the provided responses, formal or informal;

2. Object on any grounds to the use of said documents or responses in any proceeding, any litigation related to the provided responses, or any other action related to the provided responses, formal or informal, including but not limited to public relations, lobbying, and/or marketing;

3. Object on any grounds to the introduction into evidence of documents identified or produced in response to this Data Request in any proceeding, any litigation related to the provided responses, or any other action related to the provided responses, formal or informal; and/or

4. Object on any grounds at any time to other requests for production or other discovery involving said documents or responses, or the subject matter thereof.

MARIN CLEAN ENERGY

RESPONSE TO CPUC DATA REQUEST

DOCKET NO.:	N/A	**REQUEST DATE:**	June 28, 2018
REQUEST NO.:	CPUC-MCE-001	**RESPONSE DATE:**	July 30, 2018
REQUESTER:	CPUC	**RESPONDER:**	Marin Clean Energy

<u>QUESTION NO. 1</u>

Section 913.4(f) of the Public Utilities Code states that the Commission shall prepare a report including information on "the efforts each electrical corporation is taking to recruit and train employees to ensure an adequately trained and available workforce, including the number of new employees hired by the electrical corporation for purposes of implementing the requirements of Article 16 (commencing with Section 399.11) of Chapter 2.3."

(a) Please provide information on MCE's recruitment and outreach strategies for the purpose of implementing Article 16 related to RPS objectives.

(b) Please describe MCE's actions to train new RPS staff and provide your estimate of the number of employees who have undergone training sessions focused on California's RPS program.

(c) Please describe how MCE's efforts to implement RPS programs have contributed to employment growth in California.

(d) Please provide the total number of employees who have worked on RPS related issues from 2014 – 2018.

<u>MCE RESPONSE to Question 1 (a)-(d):</u>

Subject to MCE's General Statement, above, MCE provides the following response to Question 1 (a)-(d).

(a) MCE's organizational mission is to address climate change by reducing energy-related greenhouse gas emissions. A fundamental component of fulfilling this mission is meeting and exceeding California's aggressive RPS program requirements, while delivering environmentally responsible, competitively priced, and, to the extent possible, locally sourced, retail electricity options. MCE also makes efforts to prioritize and support a diverse and well-trained workforce within the confines of Proposition 209.

MCE Open Season Procurement Process ("Open Season")

To meet its RPS procurement requirements, MCE has an annual Open Season Procurement Process to solicit bids from renewable energy providers. MCE's Open Season is a competitive bidding forum for qualified energy suppliers to fulfill MCE's forecasted resource requirements. MCE evaluates bids on an objective basis by considering a common set of legally permissible criteria. MCE provides its 2018 Open Season Request for Offers Procedural Overview & Instructions in its voluntary response to this Data Request.

MCE's Sustainable Workforce and Diversity Policy 011 ("MCE Policy 011")

Underlying MCE's Open Season, procurement, contracting, and staff hiring practices is MCE Policy 011. MCE provides a copy of MCE Policy 011 in its voluntary response to this Data Request.

MCE Policy 011 states, in part: "It is a priority interest of MCE to support sustainable workforce opportunities, local economic sustainability, and diversity inclusion through contracting for power resources, procuring goods and services, and implementing hiring initiatives within a framework of competitive service and the promotion of renewable energy, customer programs, and greenhouse gas reduction."

MCE prioritizes reaching a wide range of suppliers through its power resources solicitations to ensure a robust response. To this end, MCE has used the General Order ("G.O.") 156 Clearinghouse to identify a broad and diverse pool of potential bidders for its supplier solicitations. In its power resources procurement, MCE collects information during its Open Season process that it may use to develop reporting metrics to identify workforce and diversity impacts of RPS eligible projects within the confines of Proposition 209. The collection is done through an optional questionnaire on supplier diversity and labor practices included as part of MCE's Open Season Offer Form. MCE explicitly does not give preferential treatment to bidders based on race, sex, color, ethnicity, or national origin. If such information is provided by the bidder in the optional questionnaire, this information does not impact the Open Season selection process. MCE is looking for opportunities to use the collected data to build upon MCE's current efforts to increase workforce diversity through its power procurement efforts within the confines of Proposition 209.

In addition to gathering data on workforce diversity, the Open Season questionnaire also aids implementation of MCE Policy 011 by collecting information to help MCE promote fair compensation, fair employee treatment of its suppliers, multi-trade collaboration, support of the existing wage base, and supplier diversity in communities where contracted projects will be located. Under MCE Policy 011, MCE also gives preference to power resource projects located within MCE's service territory and community service organizations and local associations serving disadvantaged and low-income communities.

For MCE-owned generation projects, MCE Policy 011 requires prevailing wages to be paid. MCE also supports local businesses, union labor, and apprentice and pre-apprenticeship programs. For MCE-developed generation projects, MCE or its contractor must employ on its regular workforce at least one employee who is enrolled and participating in a local apprenticeship program. Such apprenticeship programs must be approved by the State Department of Apprenticeship Standards.

For MCE's power purchase agreements ("PPA"), Feed-in-Tariffs, and customer programs contracting, all of which potentially contribute to MCE's compliance with the RPS program, in 2018 MCE began to request contractors voluntarily disclose their G.O. 156 Clearinghouse certification status and efforts to work with Disabled Veterans Business Enterprises ("DVBE") and Lesbian, Gay, Bi-sexual, Transgender Business Enterprises ("LGBTBE"). This information may be used post-project selection to develop metrics to measure whether MCE's procurement practices are facilitating workforce diversity within the confines of Proposition 209.

For MCE's direct staff hiring, MCE uses reasonable efforts to recruit local employees and graduates of local programs, schools, colleges, and universities. To ensure recruitment of skilled applicants, MCE develops comprehensive job descriptions to accurately reflect the requisite education and experience level to perform the essential job functions for a particular position. MCE also uses its best efforts to align compensation with regional market indicators to ensure MCE staff are fairly compensated for their contributions to MCE. To maximize workforce diversity within the confines of Proposition 209, MCE also makes efforts to distribute job announcements as widely as practicable to improve greater access to MCE opportunities by historically underrepresented groups.

(b) MCE currently employs a full-time staff of 56 regular-hire employees across 6 teams: (1) Power Resources; (2) Public Affairs; (3) Customer Programs; (4) Legal; (5) Regulatory and Legislative Policy; and (6) Internal Operations. While MCE's Power Resources, Regulatory and Legislative Policy, and Legal teams focus more directly on legal and regulatory compliance with the RPS program, MCE staff receives high-level training on power resources procurement and RPS related issues as part of MCE's employee on-boarding process. Those individuals directly responsible for MCE's power procurement are experienced, trained professionals that understand the requirements of California's RPS program. Moreover, each of MCE's teams contribute to MCE's over-arching mission to reduce energy-related greenhouse gas emissions through regulatory engagement, legal review, power procurement, community outreach, development of customer programs to reduce energy consumption, and internal operations' development of metrics and processes to track MCE's workforce and supplier diversity efforts.

MCE also offers its employees an annual professional development budget to attend conferences and trainings to keep skill-sets and knowledge current.

MCE interprets the CPUC's request for an estimate of the number of employees that have undergone RPS training as referring to MCE-specific employees/staff referenced above. Since 2015, MCE estimates that 55 employees have undergone training sessions on California's RPS program as part of their on-boarding training at MCE.

(c) MCE has committed approximately $2 billion to support approximately 924 MW of new California renewable energy projects. Of the 924 MW, approximately 120 MW represent short-term contracts entered into by MCE for California renewables projects that accelerated the delivery of renewable energy from those resources by several years.

MCE's new California renewable energy projects support direct construction labor jobs in California. MCE's activities also support indirect construction-related California jobs, including but not limited to jobs related to scheduling coordination, power settlements, data management, accounting, planning and portfolio tracking, legal and compliance work, call center staffing, and various other administrative activities.

The aforementioned indirect construction-related jobs are excluded from the construction labor jobs number reported below. MCE is developing an internal methodology to more precisely and accurately reflect the California job impacts (direct construction jobs and indirect construction-related jobs) resulting from MCE's procurement activities.

In the interim, MCE's response reports estimates derived through the use of certain Jobs and Economic Development Impact ("JEDI") models,[1] which have been developed by the National Renewable Energy Laboratory ("NREL"). Using NREL JEDI models, it is estimated that MCE's long-term renewable contracting efforts have supported (or will support via projects currently under development) approximately 4,000 construction labor jobs within California. This number excludes construction-related services,

[1] As described on NREL's website, https://www.nrel.gov/analysis/jedi/about.html:"The Jobs and Economic Development Impact (JEDI) models are user-friendly screening tools that estimate the economic impacts of constructing and operating power plants, fuel production facilities, and other projects at the local (usually state) level. JEDI results are intended to be estimates, not precise predictions." It is noteworthy that NREL has developed numerous JEDI models, each of which is associated with a particular generating technology or fuel source. NREL continues, indicating that, "Based on user-entered project-specific data or default inputs (derived from industry norms), JEDI estimates the number of jobs and economic impacts to a local area that can reasonably be supported by a power plant, fuel production facility, or other project. For example, JEDI estimates the number of in-state construction jobs from a new wind farm."

equipment and supply-chain impacts, induced job impacts, and the additional indirect construction-related impacts noted above.

As indicated in MCE's response to Question 1(a), above, MCE also implements MCE Policy 011, which prioritizes support for local businesses, union jobs, green businesses, and training and apprenticeship programs that facilitate a strong and secure workforce in the field of renewable energy project development.

Of particular note is the MCE Solar One project in Richmond, California. MCE Solar One is a 10.5 MW solar facility located on a remediated brownfield in MCE's service territory; it is the largest public-private solar project partnership in the San Francisco Bay Area. MCE Solar One is capable of producing 22,000 MW annually of RPS eligible energy, all of which is purchased by MCE to serve its customers. MCE Solar One began delivering energy to the California grid in December 2017.

MCE Solar One also complied with a local City of Richmond hiring requirement, which required 50% of the MCE Solar One workforce to be comprised of Richmond-based contractors, suppliers, and union labor. As part of MCE's workforce development and diversity efforts, MCE also partnered with and supported RichmondBUILD, a local, Richmond-based, job-training program that places its students into skilled jobs in the renewable energy sector.

MCE also partnered with RichmondBUILD in 2016 to provide labor for construction of a 2 MW MCE Feed-in-Tariff project at the Freethy Industrial Park in Richmond, California. This project provided solar installation training to RichmondBUILD apprentices.

In addition to RichmondBUILD, MCE has partnered with and funded other organizations that offer workforce development opportunities particularly for low-income and disadvantaged communities. These include partnerships with the Marin City Community Development Corp. and Rising Sun, which provided on-site training for participants in solar installation and energy efficiency upgrades, respectively.

(d) MCE interprets this question as requesting the number of MCE-specific regular-hire employees/staff who have worked to support MCE's efforts to meet and exceed California's RPS program requirements.

MCE currently employs a full-time staff of 56 regular-hire employees across 6 teams: (1) Power Resources; (2) Public Affairs; (3) Customer Programs; (4) Legal; (5) Regulatory and Legislative Policy; and (6) Internal Operations. While MCE's Power Resources, Regulatory and Legislative Policy, and Legal teams focus more directly on legal and regulatory compliance with the RPS program, all of MCE's teams contribute to MCE's over-arching mission to reduce energy-related greenhouse gas emissions through regulatory engagement, legal review, power procurement, community outreach, development of customer programs to reduce energy consumption, and internal operations' development of metrics and processes to track MCE's workforce and supplier diversity efforts.

MCE presents its total number of regular-hire employees who have worked on RPS related issues from 2014-2018.

	Year				
	2014	2015	2016	2017	2018
RPS Employees (FTE)	19	27	38	42	56

MARIN CLEAN ENERGY

RESPONSE TO COMMISSION DATA REQUEST

DOCKET NO.:	N/A	**REQUEST DATE:**	June 28, 2018
REQUEST NO.:	CPUC-MCE-001	**RESPONSE DATE:**	July 30, 2018
REQUESTER:	CPUC	**RESPONDER:**	Marin Clean Energy

QUESTION NO. 2

Section 913.4 (f) of the Public Utilities Code states that the Commission shall prepare a report including information on the "the goals adopted by the electrical corporation for increasing women, minority, and disabled veterans trained or hired for purposes of implementing the requirements of Article 16 (commencing with Section 399.11) of Chapter 2.3."

(a) Please provide the number of Women, Minority, and Disabled Veteran (WMDV) employees who have worked on RPS related issues from 2014-2018.

MCE RESPONSE to Question 2:

Subject to MCE's General Statement, above, MCE provides the following response to Question 2 (a).

(a) MCE interprets this question as requesting the number of MCE-specific regular- and extra-hire employees/staff that are women, minorities, and/or disabled veterans who have worked to support MCE's efforts to meet and exceed California's RPS program requirements.

MCE currently employs a full-time staff of 56 regular-hire employees across 6 teams: (1) Power Resources; (2) Public Affairs; (3) Customer Programs; (4) Legal; (5) Regulatory and Legislative Policy; and (6) Internal Operations. While MCE's Power Resources, Regulatory and Legislative Policy, and Legal teams focus more directly on legal and regulatory compliance with the RPS program, all MCE teams contribute to MCE's over-arching mission to reduce energy-related greenhouse gas emissions through regulatory engagement, legal review, power procurement, community outreach, development of customer programs to reduce energy consumption, and internal operations' development of metrics and processes to track MCE's workforce and supplier diversity efforts.

Taking into consideration the foregoing, MCE does not have responsive data for years 2014-2015. For years 2016-2018, MCE has responsive data to the extent the requested data is collected in the manner prescribed by the Equal Employment Opportunity Commission ("EEOC") for Form EEO-4 reporters. MCE collects this data within the confines of Proposition 209. MCE has not collected this data with respect to Disabled Veterans. The numbers provided include both regular-hire and extra-hire employees.

	RPS Employees (FTE)				
	2014	2015	2016	2017	2018
Women	Data Not Collected	Data Not Collected	26	34	39
Minority	Data Not Collected	Data Not Collected	11	14	20
Disabled Veterans	Data Not Collected	Data Not Collected	Data Not Collected	Data Not Collected	Data Not Collected

MARIN CLEAN ENERGY

RESPONSE TO CPUC DATA REQUEST

DOCKET NO.:	N/A	**REQUEST DATE:**	June 28, 2018
REQUEST NO.:	CPUC-MCE-001	**RESPONSE DATE:**	July 30, 2018
REQUESTER:	CPUC	**RESPONDER:**	Marin Clean Energy

QUESTION NO. 3

Section 913.4 (f) requests the following information: "the number of new employees hired and the number of women, minority, and disabled veterans trained or hired by persons or corporations owning or operating eligible renewable energy resources under contract with an electrical corporation" for the purposes of implementing Article 16.

(a) Please provide the number of executed RPS contracts with WMDV and LGBT business enterprises from 2014-2018.

(b) Please provide the amount of total funds spent in 2017 and 2018 on contracts meeting WMDV-LGBT business enterprise criteria.

MCE RESPONSE to Question 3 (a)-(b):

Subject to MCE's General Statement, above, MCE provides the following response to Question 3 (a)-(b).

(a) MCE is not an electrical corporation and therefore not subject to the tracking and compliance requirements of electrical corporations. MCE has not tracked or developed metrics for this data according the CPUC construct presented in this question. As such, MCE does not have current metrics that are responsive to this data request. As MCE indicates in its response to Question 1(a), as part of its Open Season, MCE provides a voluntary supplier diversity and labor questionnaire, which may be used to develop metrics for reporting purposes to identify workforce and diversity impacts of RPS eligible projects. MCE is looking for opportunities to use the collected data to build upon MCE's current efforts to increase workforce diversity through its power procurement efforts within the confines of Proposition 209.

(b) MCE is not an electrical corporation and therefore not subject to the tracking and compliance requirements of electrical corporations. MCE has not tracked or developed metrics for this data according the CPUC construct presented in this question. As such, MCE does not have current metrics that are responsive to this data request. As MCE indicates in its response to Question 1(a), as part of its Open Season, MCE provides a voluntary supplier diversity and labor questionnaire, which may be used to develop metrics for reporting purposes to identify workforce and diversity impacts of RPS eligible projects. MCE is looking for opportunities to use the collected data to build upon MCE's current efforts to increase workforce diversity through its power procurement efforts within the confines of Proposition 209.

August 30, 2018

CPUC Energy Division
Attention: ED Tariff Unit, 4th Floor
505 Van Ness Avenue
San Francisco, CA, 94102

RE: Protest of the Joint DA/CCA Parties on Pacific Gas and Electric Company's Advice Letter 5353-E, Southern California Edison Company's Advice Letter 3844-E and San Diego Gas & Electric Company's Advice Letter 3260-E on Determining a Bill Credit to End Cost Recovery from the Customers of a Competing Demand Response Provider

Pursuant to Section 7.4 of California Public Utilities Commission ("Commission") General Order ("G.O.") 96-B, the Alliance for Retail Energy Markets[1] ("AReM"), Direct Access Customer Coalition[2] ("DACC"), Marin Clean Energy[3] ("MCE"), Sonoma Clean Power ("SCP"),[4] and the California Choice Energy Authority ("CCEA")[5] ("Joint DA/CCA Parties")

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[1] AReM is a California non-profit mutual benefit corporation formed by electric service providers that are active in the California's direct access market. This filing represents the position of AReM, but not necessarily that of a particular member or any affiliates of its members with respect to the issues addressed herein.

[2] DACC is a regulatory alliance of educational, commercial, industrial and governmental customers who have opted for direct access to meet some or all of their electricity needs. In the aggregate, DACC member companies represent over 1,900 MW of demand that is met by both direct access and bundled utility service and about 11,500 GWH of statewide annual usage.

[3] MCE is the first operational CCA program in California and began serving its customers in May 2010 in order to reduce electricity-related greenhouse gas ("GHG") emissions. MCE currently serves approximately 470,000 customer accounts in Marin County, Napa County, unincorporated Contra Costa County, Benicia, Concord, Danville, El Cerrito, Lafayette, Martinez, Moraga, Oakley, Pinole, Pittsburg, Richmond, San Pablo, San Ramon, and Walnut Creek. MCE's operations are overseen by its Board of Directors comprised of publicly elected officials representing each of the communities participating in MCE's CCA program.

[4] SCP is a CCA program that currently serves the Counties of Sonoma and Mendocino, and the Cities of Cloverdale, Cotati, Fort Bragg, Petaluma, Point Arena, Rohnert Park, Santa Rosa, Sebastopol, Sonoma, Willits, and Windsor.

[5] CCEA is a California joint powers authority initially formed by the cities of Lancaster and San Jacinto, with expanding membership available to other cities interested in implementing CCA programs using services provided by the CCEA. Currently, the cities of Lancaster, San Jacinto, Rancho Mirage and Pico Rivera are members of CCEA. Under the hybrid model established by CCEA, individual cities maintain the role of Community Choice Aggregators in the implementation of CCA programs, with CCEA

submit this protest to the August 10, 2018 advice letter submitted by Pacific Gas and Electric Company ("PG&E) (Advice Letter 5353-E), Southern California Edison Company ("SCE") (Advice Letter 3844-E), and San Diego Gas & Electric Company ("SDG&E") (Advice Letter 3260-E). This Joint Advice Letter ("AL") proposes methodologies to determine a bill credit for the customers of a Competing Demand Response ("DR") Provider, which could be either an Electric Service Provider ("ESP") or a Community Choice Aggregator ("CCA"), as directed by Decision ("D.") 17-10-017. The Joint DA/CCA Parties have reviewed and hereby protest this AL.

The AL consists primarily of a separate, proposed approach submitted by each Investor-Owned Utility ("IOU") to implement the bill credit. While the respective approaches have some common elements, they differ, particularly with respect to the costs each IOU proposes to include in the bill credit. While SCE has made a good faith effort to include all applicable costs, PG&E and SDG&E propose to restrict the costs to be included in the bill credit, an approach unsupported by the specific directives in D.17-10-017. In addition, D.17-10-017 provided the IOUs the opportunity to request recovery of costs incurred for implementing the bill credit in this AL, but set forth requirements that the IOUs were to meet in seeking such cost recovery. PG&E and SDG&E each requested cost recovery, but fell far short of meeting the stated requirements. Finally, certain aspects of the proposals by PG&E and SDG&E require clarification or submission of supplemental information before their proposals can be adequately assessed by stakeholders and the Commission.

The Joint DA/CCA Parties respectfully request that the Commission:

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providing support services, including rate analysis, billing assistance, power procurement, utility relations and regulatory affairs.

- Require PG&E and SDG&E to specify appropriate portions of Category 6 (ME&O) and Category 7 (Portfolio Support) to be incorporated into the bill credit, as discussed herein.
- Reject the proposals by PG&E and SDG&E for recovery of implementation costs for the bill credit as unreasonable and non-compliant with D.17-10-017.
- Reject any proposal for recovery of implementation costs for the bill credit that does not include mandatory, detailed cost disclosures and Commission reasonableness review.
- Require PG&E and SDG&E to clarify their proposals or submit supplemental information as outlined herein.

I. BACKGROUND

One of the main issues litigated in the 2013 Demand Response Rulemaking ("R.") 13-09-011 was the rules the Commission should apply in the event that similar or overlapping DR programs are offered by both the IOU and an ESP or CCA. After extensive discussion and comments by parties, the Commission established the competitive neutrality cost causation principle in D.14-12-024:[6]

> Hence, we adopt the competitive neutrality requirement that once a direct access and community choice aggregation provider begins to offer a demand response program, the competing utility shall discontinue cost recovery from that providers' customers for that or any similar program, no later than one year following the implementation of that program.[7]

[6] D.14-12-024, Ordering Paragraph 8b.

[7] D.14-12-024, pp. 49-50 and Ordering Paragraph 8b.

The Commission adopted this important principle specifically to remove competitive barriers for ESPs and CCAs.[8] Moreover, an essential component to achieving "competitive neutrality" was the Commission's determination that the IOUs would be required to "***end cost recovery***" from customers of the ESPs and CCAs offering similar DR programs.[9]

The Commission subsequently approved D.17-10-017, which set forth precise requirements for implementing the cost causation principle, including adoption of the IOUs' proposal for a bill credit to fulfill the requirement to "end cost recovery" from ESP and CCA customers.[10] Specifically, the Commission directed the following with respect to the bill credit:

- Adopted the IOUs' proposal for a bill credit.[11]
- Required the IOUs to submit, within 90 days of the issuance of D.17-10-017, a "proposed approach for ***determining*** the bill credit."[12]
- Required that the "same basic approach will be used by the Utilities."[13]
- Required the IOUs to include in the 90-day submittal a "draft standardized customer letter noticing and explaining the process"[14] and explaining the bill credit to "alleviate customer confusion.[15]

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[8] D.14-12-024, p. 49: "While we will not authorize funding to Marin Clean Energy to implement its own demand response programs, ***we acknowledge the barrier to creating such a program***. Hence, we adopt the competitive neutrality requirement …" (emphasis added)

[9] D.14-12-024, Ordering Paragraph 8b.

[10] D.17-10-017, p. 28.

[11] D.17-10-017, p. 28. See also, Conclusion of Law No. 11, Ordering Paragraph 1, and Attachment 1, Step Four.

[12] D.17-10-017, Ordering Paragraph 3. Emphasis added.

[13] D.17-10-017, p. 29. The Commission noted that there may be "slightly different approaches by each utility" considering the "utility systems are not exactly the same." See also, Ordering Paragraph 4.

[14] D.17-10-017, Ordering Paragraph 3.

[15] D.17-10-017, Finding of Fact 21 and p. 28.

- Required a "public process to determine the bill credit"[16] and directed Energy Division to hold a workshop within 60 days of the IOUs' submittal to discuss the IOUs' proposed approach and "develop a consensus."[17]
- Required the IOUs to "work with the parties" and, within 30 days of the workshop, to submit a Tier Three Advice Letter for Commission approval of the "consensus approach" or to submit "one of the proposed approach[es] and "describe all alternatives."[18]

On January 30, 2018, the IOUs provided a joint submittal purporting to propose an approach to determine the bill credit. However, as detailed in the informal comments submitted by the Joint DA/CCA Parties, the IOUs failed to comply with the very first step of the process specified in D.17-10-017 – to submit an approach to ***determine*** the bill credit for direct access ("DA") and CCA customers.[19] The Joint DA/CCA Parties recommended that the Commission reject the IOUs' submittal as non-compliant. However, Energy Division elected to proceed with workshops to discuss both the IOUs' submittal and supplemental information that Energy Division had requested from the IOUs.

As outlined in the AL,[20] the participants in the workshops were able to reach consensus regarding certain aspects of the bill credit, including the text of the customer notification letter

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[16] D.17-10-017, p. 28 and Conclusion of Law 12.
[17] D.17-10-017, Ordering Paragraph 4.
[18] D.17-10-017, Ordering Paragraph 5.
[19] *Informal Comments of the Alliance for Retail Energy Markets, Direct Access Customer Coalition, Marin Clean Energy, Sonoma Clean Power, and the California Choice Energy Authority on Joint Utilities' Proposed Approach to Determine the Bill Credit for the Customers of Competing Demand Response Providers,* March 1, 2018.
[20] IOUs' AL, pp. 4-5.

required by Ordering Paragraph 3 of D.17-10-017. Further, on July 18, 2018, SCE filed a Petition to Modify D.17-10-017 on behalf of the Joint DA/CCA Parties and others to seek needed clarifications. Nonetheless, workshop participants were unable to reach consensus on important aspects of the bill credit approach, in particular the costs to be included in the bill credit to the customers of the Competing DR Provider.

II. GROUNDS FOR PROTEST

The Joint DA/CCA Parties protest this advice letter on the following grounds:

- PG&E and SDG&E propose to exclude applicable costs from the bill credit in violation of D.17-10-017.
- PG&E and SDG&E fail to meet the requirements in D.17-10-017 to justify recovery of implementation costs of the bill credit.
- Some aspects of PG&E's and SDG&E's proposals require clarification or submission of supplemental information.

III. DISCUSSION

a. The proposed approaches of PG&E and SDG&E improperly exclude applicable costs from the bill credit.

D.17-10-017 repeatedly directs the IOUs to construct the bill credit to "end cost recovery" of the IOUs' similar DR program.[21] The decision also references the need to "cease" or "end" such cost recovery.[22] The clear requirement is that all applicable IOU program costs are to be included in the bill credit to: 1) ensure competitive neutrality between the IOUs, on the

[21] D.17-10-017, p. 8, Conclusion of Law 11 and Ordering Paragraphs 3 and 4.

[22] See, D.17-10-017, pp. 27 and 28, Attachment 1, Steps Three and Four.

one hand, and ESPs and CCAs on the other; and 2) ensure that ESP and CCA customers are not charged for an IOU program that they neither cause nor benefit from; and 3) ensure that ESP and CCA customers are not "double-charged" for the same DR program costs by both their distribution IOU and their ESP or CCA.

Just as the IOUs have staff, computers, offices, marketing materials, training and regulatory support, internet capabilities, and other essentials to carry out their programs effectively, so must the ESPs and CCAs. In short, the ESPs and CCAs must develop their own staff, technical capabilities, marketing tools, training, and infrastructure to develop and effectively manage a competing DR program. Thus, to ensure competitive neutrality and eradicate current barriers, the bill credit must incorporate all the costs incurred by the IOUs in developing, operating and managing the competing DR program. Failing to incorporate all such charges would also expose CCA and ESP customers to unjust and unreasonable double-charges.

Among the IOUs, only SCE seemed to make a good-faith effort to comply with these clear requirements. SCE enumerates the costs[23] it proposes to include in the bill credit, including a portion of Marketing, Education and Outreach ("ME&O") (Category 6) and Portfolio Support (Category 7) costs.[24] SCE also provided clear and understandable explanations of how the bill credits would be calculated and listed sample bill credits by customer class for its Base

[23] The "category" of costs discussed herein refers to the seven categories specified in D.17-12-003, Attachment 3: Category 1 – Supply-Side DR Program; Category 2: Load Modifying DR Program; Category 3 – DR Auction Mechanism (DRAM) and Direct Participation Electric Rule 24/32; Category 4 – Emerging and Enabling Technology Program; Category 5 – Pilots; Category 6 – Marketing, Education and Outreach (ME&O); and Category 7 – Portfolio Support (included EM&V, Systems Support, and Notifications)

[24] IOUs' AL, Attachment A (SCE), pp. 3-4.

Interruptible Program ("BIP") and Capacity Bidding Program ("CBP").[25] SCE explained that it proposes to exclude certain Category 7 costs from the bill credit: Meter Reprogramming; the DR Potential Study; and the credit for the eliminated Permanent Load Shift ("PLS") program.[26] The Joint DA/CCA Parties concur with these exclusions. SCE's representative was further able to confirm that the costs it proposed to incorporate into the bill credit included administration and overhead costs associated with specific budget items. The Joint DA/CCA Parties appreciate SCE's approach, which complied with both the spirit and the letter of D.17-10-017.

On the other hand, PG&E and SDG&E took a different – and nearly identical – approach. Both PG&E and SDG&E argue that the only costs to be included in the bill credit are those "directly attributable" to the competing DR program.[27] However, the clear language of D.17-10-017 does not support this interpretation.

For example, PG&E states that "indirect costs," which it refers to as "unavoidable or fixed costs," would <u>not</u> be incorporated into the credit,[28] thereby excluding most of Category 6 (ME&O) and all of Category 7 (Portfolio Support) costs. PG&E's table summarizing the cost categories not applicable to bill credit identify them as "unavoidable – benefits all programs."[29] In support, PG&E reiterates some of its rhetoric from the IOUs' January 30th submittal, arguing that these budget items are "essential" and warning of a "tipping point" if the costs are included in a bill credit.[30]

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[25] IOUs' AL, Attachment A (SCE), pp. 6-9.
[26] IOUs' AL, Attachment A (SCE), p. 4.
[27] IOUs' AL, Attachment B (PG&E), p. 2 and Attachment C (SDG&E), p. 2.
[28] IOUs' AL, Attachment B (PG&E), pp. 2-4.
[29] IOUs' AL, Attachment B (PG&E), p. 11, Appendix B.
[30] IOUs' AL, Attachment B (PG&E), pp. 2-3.

PG&E's arguments fall of their own weight. Each of the "indirect costs" identified by PG&E is duplicative of costs that will be incurred by the Competing Provider and paid by the Competing CCA or ESP customers and would unjustly recover costs for expenditures that neither benefit nor are caused by these customers.

PG&E argues that the "DR Integration and Policy" and "Support for Market Activities" sub-categories should be excluded from the bill credit because they fund PG&E's support of CAISO markets. However, supporting CAISO markets is a function the ESPs and CCAs must also perform, and equivalent costs will be incurred in implementing any competing DR program. PG&E argues that it needs policy and regulatory support for its CPUC and CAISO activities, but so do the ESPs and CCAs. PG&E says its "essential" budget items "support important State policy" and advance "clean energy programs," but all DR programs fit this bill, including those provided by ESPs and CCAs. PG&E declares its EM&V team "participates in numerous regulatory activities" and supports "core" DR programs including CPP.[31] However, PG&E will no longer be providing EM&V services for the Competing Provider's program. Moreover, the Competing Provider is separately required by D.17-10-017 to conduct and submit analysis of its own program and thus will incur any related costs for doing so.[32] Moreover, CPP is a bundled customer program and all related costs, including EM&V, should be recovered in generation rates. To do otherwise is anti-competitive. In short, PG&E fails to make any reasonable case why such costs should be excluded from the bill credit, and excluding these costs would clearly violate cost causation.

[31] IOUs' AL, Attachment B (PG&E), p. 3.
[32] D.17-10-017, Ordering Paragraph 6.

SDG&E makes the same general claims as PG&E, but does not even bother to provide either the specific costs it considers to be "directly attributable" or those it plans to exclude from the bill credit. SDG&E does provide a list of the costs that "may" be included in the bill credit as directly attributable, but no explanation of when they would <u>not</u> be included.[33] Further, SDG&E offers only a brief and vague discussion of indirect costs that it plans to exclude from the bill credit, which seems to encompass Category 7 (Portfolio Support) in its entirety.[34] Like PG&E, SDG&E argues that it must retain these revenues for itself to "support important State policy,"[35] as if only an IOU-sponsored DR program can fulfill state policy.

In fact, a plain reading of D.17-10-017 provides no support for the assertions of PG&E and SDG&E. The decision clearly and concisely orders the IOUs to "end cost recovery." In no place does the decision limit the bill credit to "avoidable" costs or costs "directly attributable" to a particular DR program. The mandate to "end cost recovery" must logically include costs in both Category 6 (ME&O) and 7 (Portfolio Support), as SCE has acknowledged. As noted above, ESPs and CCAs incur their own costs to develop, implement, and manage the competing DR program; their customers should not be on the hook to pay for these same costs for the IOU. Moreover, the Commission devised the bill credit as a tool to ensure competitive neutrality. That tool is blunted or made ineffective to the extent the IOUs refuse to include appropriate costs in the bill credit.

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[33] IOUs' AL, Attachment C (SDG&E), p. 2.
[34] IOUs' AL, Attachment C (SDG&E), p. 3.
[35] *Ibid.*

Accordingly, the Joint DA/CCA Parties respectfully request that the Commission require PG&E and SDG&E to specify appropriate portions of the costs in Category 6 (ME&O) and Category 7 (Portfolio Support) to be incorporated into the bill credit, as follows:

- For PG&E:
  - Category 6:
    - DR Core Marketing and Outreach
    - Education and Training
  - Category 7:
    - DRMEC
    - DR Integration Policy & Planning
    - Support for Market Activities
    - Support for Retail & Customer-Facing Activities
- For SDG&E:
  - Category 6:
    - Local, Marketing Education and Outreach
  - Category 7:
    - Regulatory Policy & Program Support
    - IT Infrastructure & Systems Support
    - EM&V

b. The bill credit implementation cost recovery proposals presented by PG&E and SDG&E should be rejected because they are unreasonable and fail to meet the requirements of D.17-10-017.

In D.17-10-017, the Commission laid out clear requirements for IOUs seeking to recover costs associated with implementing the bill credit proposal:

> The Utilities may include in this Tier Three Advice Letter, a proposal for recording incremental costs associated with implementing the bill credit approach, a forecast of the activities and costs, and the proposed rate recovery.[36]

As a threshold matter, it is worth noting that D.17-10-017 in no way finds that the recovery of DR bill credit implementation costs is necessary, fair, or reasonable, nor does the Decision pre-authorize any such recovery. The Decision merely establishes a process through which IOUs may submit proposals to justify recovery of such costs. In light of the Decision's unambiguous endorsement of the principle of cost causation, it is clear that only the most persuasively established, unavoidable implementation costs should be authorized for recovery, and even then such costs should be viewed critically and kept to a *de minimis* level. ESP and CCA customers should not have to pay unreasonable charges to have their own money refunded to them, and the Commission should be mindful of the fact that the IOUs, not CCAs and ESPs, are in the best position to avoid unreasonable implementation costs.

In the AL, both PG&E and SDG&E provide implementation cost recovery proposals (SCE, which did not provide an implementation cost recovery proposal, is presumably not seeking implementation cost recovery). Neither PG&E's proposal nor SDG&E's proposal meets the clear requirements of D.17-10-017. PG&E's proposal is as follows:

> PG&E proposes to track the implementation costs in the Demand Response Expense Balancing Account (DREBA) and to transfer these costs to the Distribution Revenue Adjustment Mechanism (DRAM) for recovery through PG&E's Annual Electric True-up filing. Essentially, the costs associated with the implementation of the bill credit would be captured in the overall program costs borne by all customers. PG&E believes these costs should be recoverable without a reasonableness review.[37]

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[36] D.17-10-017, p. 29.

[37] IOUs' AL, Attachment B (PG&E), p. 8-9

Similarly, SDG&E states:

> SDG&E proposes to track the implementation costs of the credit in its Advanced Metering and Demand Response Memorandum Account (AMDRMA). Under SDG&E current ratemaking process, at year-end, the AMDRMA's distribution sub-account balance is transferred to SDG&E's Rewards and Penalties Balancing Account (RPBA) for cost recovery in the following calendar year. Essentially, the costs associated with the implementation of the bill credit would be captured in the overall program costs borne by all customers. Because SDG&E collects its DR costs in this manner, one year in arrears, the amount that is shifted to all customers will include necessarily the under-collected amount of DR costs from that SDG&E DR program that is similar, for the months that would have extended past 365 days. SDG&E believes these costs should be recoverable without a reasonableness review.[38]

These proposals fail to meet the requirements of D.17-10-017. Neither PG&E nor SDG&E provide any detail regarding the specific incremental costs, including the "forecast of the activities and costs" that would be included under their respective implementation cost recovery proposals as required by D.17-10-017. Without this basic information, it is impossible for the Commission to determine whether the costs in question are reasonable.

Further, both PG&E and SDG&E request that implementation costs be "recoverable without a reasonableness review." This request is highly problematic. As stated above, the IOUs, not the ESPs and CCAs, are in the position to mitigate implementation costs. If implementation costs are fully allocated to Competing Providers' customers, then it is not clear that the IOUs will have any incentive to limit these costs or ensure that they are just and reasonable. To the contrary – given the fact that ESPs and CCA programs are *competing providers*, the IOUs have a perverse incentive to inflate implementation costs to reduce the DR bill credit and, in turn, reduce the competitiveness of CCA and ESP DR programs. As stated

[38] IOUs' AL, Attachment C (SDG&E), p. 6-7

above, the fact that the IOUs are the best (and only) parties with control over implementation costs provides a strong economic argument against allowing the IOUs to impose implementation costs on Competing Providers.

However, if the Commission does authorize the IOUs to impose any implementation costs on Competing Providers, it must do so in a manner that ensures the highest level of transparency and ensures that only reasonable, incremental, and truly unavoidable implementation costs are imposed. This includes, at a minimum, ongoing Commission oversight including, but not limited to, detailed mandatory cost disclosures by the IOUs and regular reasonableness reviews by the Commission.

c. Certain aspects of PG&E's and SDG&E's proposals require clarification or submittal of supplemental information.

Customers Receiving No Bill Credit

PG&E states that it will include a six-decimal point credit on its rate table for E-20T customers, but that the "billing architecture would remain at five decimal places."[39] This statement seems to indicate that the customers do not actually receive the bill credit to which they are entitled pursuant to D.17-01-017. PG&E should be required to clarify its proposed approach. Similarly, SDG&E states that the bill credit will only be provided to customers if the $/kWh credit for their customer class is at least $.00001 (rounded).[40] D.17-01-017 did not provide the IOUs with the opportunity to avoid providing a bill credit to entire customer classes.

PG&E's Proposed "Communications"

[39] IOUs' AL, Attachment B (PG&E), p. 5.
[40] IOUs' AL, Attachment C (SDG&E), p. 4.

PG&E states that it plans separate communications with ESP and CCA customers regarding the bill credit.[41] For example, PG&E proposes an "on-bill message" regarding the bill credit, which the Joint DA/CCA Parties do not oppose. PG&E also states its intention to provide a draft of the on-bill message to the affected ESP or CCA in advance, which the Joint DA/CCA Parties strongly support. However, it is unclear whether PG&E plans other "external communications." The Joint DA/CCA Parties request additional details on PG&E's communication plans, particularly if such communications affect CCA or DA customers.

Inadequate Information Provided

Unlike SCE, neither PG&E nor SDG&E provided sample bill credits by customer class. The Joint DA/CCA Parties find this omission odd because such information was exchanged in the workshops. Further, SDG&E failed to identify its DR programs subject to the bill credit. The Joint DA/CCA Parties request that the Commission require the IOUs to provide this additional information, which will assist CCAs and ESPs in their decision-making process for establishing a competing DR program and add transparency to the IOUs proposals for calculating and allocating the bill credit.

IV. REQUEST FOR RELIEF

The Joint DA/CCA Parties respectfully request that the Commission:

- Require PG&E and SDG&E to specify appropriate portions of Category 6 (ME&O) and Category 7 (Portfolio Support) to be incorporated into the bill credit, as discussed herein.

[41] IOUs' AL, Attachment B (PG&E), p. 6.

- Reject the proposals by PG&E and SDG&E for recovery of implementation costs for the bill credit as unreasonable and non-compliant with D.17-10-017.
- Reject any proposal for recovery of implementation costs for the bill credit that does not include mandatory, detailed cost disclosures and Commission reasonableness review.
- Require PG&E and SDG&E to clarify their proposals or submit supplemental information as described above.

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.	**R.17-06-026** **(Filed June 29, 2017)**

COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON ADMINISTRATIVE LAW JUDGE'S PROPOSED DECISION

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BEFORE THE PUBLIC UTILITIES COMMISSION
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COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION ON ADMINISTRATIVE LAW JUDGE'S PROPOSED DECISION

Pursuant to Rule 14.3 of the California Public Utilities Commission (CPUC) Rules of Practice and Procedure, the California Community Choice Association (CalCCA) submits these comments on the proposed decision of Administrative Law Judge (ALJ) Roscow (PD).

I. INTRODUCTION AND SUMMARY

The Proposed Decision reflects careful legal analysis, an impressive synthesis of a large, data-intensive record and the intent to reasonably balance the interests of bundled and departing load customers in equitably allocating Power Charge Indifference Adjustment (PCIA)-eligible costs. Several aspects of the PD contribute significantly to its balance. First, the PD is faithful to the Legislature's directives regarding the scope of PCIA-eligible resources. Second, it recognizes the transitional and longer term dimensions of the problem, maintaining the existing methodology during the transition to a voluntary, market-based long-term solution. Third, it recognizes, through the adoption of a cap and collar on the PCIA, the potential destabilizing effect of the significant changes it proposes to the existing PCIA benchmark.

Despite these strengths, CalCCA recommends limited modification and refinements of the PD. The final decision should:

- ✓ Abandon the PD's proposed "true up" process because it is insufficiently developed and not be ready for implementation.

- ✓ In the absence of abandoning it, clarify that the annual "true up" will true-up costs, revenues and load, but will not adjust the forecast estimate of portfolio value. This approach (1) achieves the goal of precision where precision can be attained; (2) recognizes the inherent uncertainties and complexities in valuing the "value of benefits that remain with bundled service customers," and (3) reduces the disruption in predictability, certainty and stability of the PCIA caused by the annual true-up.

- ✓ Reject the PD's "bottom of the barrel" capacity valuation, replacing it with a product-specific, weighted-average benchmark that more reasonably reflects the real-world stratification of capacity value.

CalCCA also recommends providing a clearer road map for the long-term, voluntary, market-based solution that will be explored in a new phase of this proceeding. In particular, this should leave open the possibility for redistribution of more than just the "excess" in the utilities' portfolios and should state a policy preference for the development of verifiable long-term valuation benchmarks for calculating and allocating PCIA-eligible costs.

II. THE TRUE-UP MECHANISM ADDS INSTABILITY TO THE PCIA AND SHOULD BE ABANDONED OR ALTERNATIVELY SHOULD BE REFINED.

The PD concludes that "[a] true-up mechanism should be adopted to ensure that bundled and departing load customers pay equally for PCIA-eligible resources."[1] The PD errs in four respects. First, the PD fails to provide sufficient detail to understand the nature of the true-up it recommends. Second, the true-up does not square with Guiding Principle 1.b., which requires that any solution "should have reasonably predictable outcomes that promote certainty and stability for all customers within a reasonable planning horizon."[2] Third, any assumption that the "value of any benefits that remain with bundled service customers" can be determined with a level of precision that warrants a true-up is erroneous. Fourth, certain portfolio costs, particularly associated with RA capacity, are set in base rates in general rate cases and are not updated for bundled customers. Therefore, there is no basis for updating RA costs and values for departed customers.

A. Calculating PCIA-Eligible Costs

The limits of a PCIA true-up can best be understood by examining the process for determining and allocating PCIA costs. PCIA-eligible costs are equal to net portfolio costs – costs less revenues -- reduced by the value of the portfolio remaining to serve bundled customers.[3]

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1 Proposed Decision, Conclusion of Law 16, at 126.

2 Scoping Memo at 14.

3 Net costs must be reduced by the "value of the any benefits remaining with bundled service customers." Cal. Pub. Util. Code §366.2(g).

The first step, determining net portfolio costs, can be done precisely. The costs of the utility portfolio are actually known in hindsight through CAISO settlement and bilateral sales revenues, along with the relative proportion of bundled and departing load customers.

Unlike these elements of the calculation, valuation of capacity, RPS and other attributes that remain in the utility portfolio to serve bundled customers necessarily requires estimation – proxies -- since these products are not transacted in the market. In other words, truing up an estimate, using values that are not necessarily representative of the value of remaining portfolio attributes, as discussed in Section II.D, is just substituting one estimate with another and will not add to precision.

B. The PD's Recommended True-Up Lacks Clarity.

While the PD recommends a true-up, it fails to specify what elements of the PCIA calculation will be subject to the true-up. The PD simply references a utility exhibit (Exhibit IOU-1)[4] that was based on the adoption of PAM/GAM, which only provided "general concepts" and has no relevance to the overall framework proposed by the PD. Without greater analysis and definition, the true-up as proposed cannot be implemented.

The calculation presented in Exhibit IOU-1 does not explain how a true-up would be applied in the PD's PCIA benchmark framework. The PD does not explain how that calculation, based on the GAM/PMM, could be applied to the PCIA benchmark framework. One conclusion that can be drawn, however, is that the true-up was intended to focus on only the elements of the PCIA for which there are actual transaction values: costs and revenues. The Joint Utilities state that "[w]hile the initial rates for both the PMM and GAM portions of the portfolio will be set in the Joint Utilities' respective annual Energy Resource Recovery Account (ERRA) Forecast proceedings based on a forecast of costs and offsetting market revenues (forecast net resource costs), those rates will be trued-up annually based on actual portfolio performance and realized

[4] *See* Exh. IOU-1 at 1-21.

market revenues (actual net resource costs), **<u>as well as billed revenues (i.e., sales) received from customers</u>**.[5] TURN's position similarly focuses on actual market revenues:

> "At the end of the year, the net costs of the PCIA resources should be calculated based on the recorded gross costs of the resources **<u>minus the revenues such resources earn in relevant markets</u>**. These markets would include sales into the energy and ancillary services markets operated by the CAISO along with revenues from forward sales of energy, renewable energy and RA capacity to other market participants."[6]

The gist of the discussion suggests a true up of costs and revenues actually realized or transacted.

If, instead, the PD intended to true-up the forecast cost of the untransacted portfolio remaining to serve bundled customers, it fails to explain the mechanics or the benefits of this approach. Bundled sales under the utility generation tariff rates are the only transactions that exist where resources used to serve bundled load actually generate "billed revenues (i.e., sales) received from customers"[7] or "the revenues such resources earn in relevant markets."[8] Accordingly, using the criteria proposed by TURN and the Joint Utilities, the only "revenues" available to true up costs would be the revenues the utility receives for the sale of the products to bundled customers.[9] There is no other transacted or realized value, and using anything other than the sale to bundled customers would effectively invent a non-existent transaction that was never made (sales of the bundled supplies assumed to be made at the prices earned from transactions in which the non-bundled supply is sold). Moreover, it is not clear what the benefit would be of truing up one portfolio value estimate to another estimate – particularly if both are based on referents that do not reasonably represent the value of the remaining portfolio products.

ORA's proposal, which the PD also cites, appears to offer more clarity. As the PD explains, ORA's true-up would be "based on actual portfolio performance and

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5 Exh. IOU-1 at 1-22:29-23:3.
6 Proposed Decision at 79 (quoting TURN Opening Brief at 16).
7 Exh. IOU-1 at 23:23.
8 Exh. TURN-1 at 8:22-23.
9 Here we are referring to the fully-allocated cost of service rate for generation service charged to bundled load customers, not the much smaller synthetic rate components identified in the Joint Utilities' testimony (e.g., the balancing accounts and subaccounts such as PABA, PMM, GAM, CTC, etc.).

market settlement data," which could be "'audited and verified in the IOUs' ERRA Compliance applications.'"[10] The most reasonable interpretation of this proposal is that actual costs and actual revenues will be subject to true-up – not the portfolio estimate.[11]

Any true-up, as discussed below, will undermine predictability, stability and uncertainty for departing load customers and their LSEs. The Commission should reject any true-up or, at a minimum, any true-up should be clarified and limited to a true up of actual load, costs and revenues as proposed in Section E.

C. A True-Up Does Not Comport With Guiding Principle 1.b.

Guiding Principle 1.b. adopted in the Scoping Memo requires that any solution "should have reasonably predictable outcomes that promote certainty and stability for all customers within a reasonable planning horizon."[12] A true-up lacks predictability and does not promote certainty and stability. On these grounds, a true-up should be rejected.

Today, a CCA knows its PCIA responsibility before going into a year and making additional procurement decisions. The PCIA is forecast in the Forecast ERRA, without subsequent true-up. This approach allows the CCA certainty in managing its portfolio. The PD, however, would upset this balance. A CCA would be required not only to the risk of its own procurement decisions – a risk all LSEs must manage – but the risk of PCIA variations resulting from the utility's portfolio management. While the utility will be fully aware of changes in portfolio costs or values throughout the year and can take that knowledge into account in its procurement decisions, the CCA will have no visibility into those decisions or the potential effects on the PCIA. Critically, recognizing the different positions of utility and non-utility LSEs in this respect requires efforts to mitigate the risk of PCIA fluctuation for non-utility LSEs. A true-up does not manage this risk, it exacerbates the risk.

The true-up thus fails to provide predictability, certainty and stability, as required by Guiding Principle 1.b., and should be modified as proposed in Section D below.

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10 Proposed Decision at 79 (quoting ORA Opening Brief at 141).

11 Even ORA's proposal requires additional clarification, as do TURN's and the IOU's true up proposals, that **all** generation revenues, including from sales of ancillary services and other operating revenues, be included and netted against portfolio costs.

12 Scoping Memo at 14.

D. A True-Up of the "Value of Benefits Remaining With Bundled Customers" Would Be Illusory.

A true-up of load, costs and revenues could achieve a greater degree of precision in outcome, but would come at a cost to predictability, certainty and stability. The suggestion that greater precision can be achieved by truing up the value of portfolio benefits remaining with bundled customers – benefits that are not measured by actual transactions -- is highly misleading.

The benchmarks used to value the unsold utility portfolio, whether in the existing or PD methodology, will always be but proxies for the value of the remaining products and attributes. The actual "receipts" received for the sale of the utility's *excess* RA capacity, for example, may bear little or no relationship to the value of the long-term capacity benefits remaining within the portfolio to be used by bundled customers.[13] Attributes remaining in the portfolio, for example, provide a "buffer" for failing to meet statutory or Commission-established requirements,[14] and mitigate price risk[15] - value not transferred to the buyer in the short-term transactions.

The problems with buying into the Joint Utilities' "precision" arguments are discussed more extensively in CalCCAs' Reply Brief.[16] Portfolio valuation – valuation of products that are not transacted in the market – is not an exercise conducive to precision, as the Legislature recognized. Consequently, even ignoring the failure of the true-up to provide predictability, stability and certainty, a true-up of *all* elements of the PCIA calculation is unreasonable and contrary to statute.

E. Any True-Up Must Be Clarified and Limited to Actual, Measurable Values.

While CalCCA continues to oppose a true-up due to concerns over rate predictability and stability, if a true-up is adopted, the final decision should clarify its scope and mechanics. At most, it should allow a true-up of load, actual generation costs and actual market revenues for product sales – all values that can be actually measured and for which "receipts" actually exist. A true-up should not, however, provide a true-up of the forecast value of portfolio products and attributes that are not transacted in the market, unless it incorporates the revenue from bundled load sales at full utility generation tariff rates, as described above. A methodology that permits a true-up of the volume of RA and RPS attributes remaining in the utility portfolio using only

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13 The problem is further described in Section IV.

14 *See, e.g.,* Exh CalCCA-102-C at 2-4; *see also* 1 Tr.-C 180-184.

15 5 Tr. 900:8-16 (Hoekstra).

16 CalCCA Reply Brief at 19-20.

short-term market value measures, would ignore Public Utilities Code §366.2(f)(2) and create volatility *without* gaining precision.

Regardless of its formulation, any true-up will create added volatility and risk for non-utility LSEs to manage. Consequently, adequately collaring the PCIA annual changes, as discussed in Section V is critical to the success of this approach.

III. THE CAPACITY BENCHMARK SHOULD BE MODIFIED TO MORE REASONABLY REPRESENT THE VALUE OF CAPACITY.

The PD adopts TURN's proposal to reduce the RA capacity benchmark by roughly half. Today, the capacity benchmark is based on the "'going forward cost (sum of insurance, ad valorem and fixed operations and maintenance costs) of a combustion turbine'" that is available to serve the grid when required,[17] which yields a value of approximately $58.27 kW-year, or approximately $4.86/kW-month on average. Based *solely* on TURN's comparison of this price to the prices reported in the Energy Division's RA Report and disregarding the extensive evidence in the case regarding long-term benchmarks, the PD recommends that the capacity benchmark be "calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions made during (year n-1) for deliveries in (year n)."[18] It also recommends a "zero or de minimis price" for any capacity that remains unsold.[19]

In its choice of capacity benchmark, the PD misses the primary aim of the proceeding, avoiding cost shifts, and exacerbates the existing cost shift from bundled to departing load customers. The PD's use of this capacity value price referent:

- Significantly undervalues the capacity, failing to recognize the "buffer" and hedging value provided by portfolio resources.[20]

- Is directly at odds with the Commission's continued long-term valuation of capacity for other purposes -- distributed energy resources cost-effectiveness evaluations, bundled procurement and rate-setting.[21]

- Implicitly accepts the untenable notion that long-lived power supply resources have long-term planning, hedging and resource diversity value *up until the very moment* they are

17 Proposed Decision at 37.
18 *Id.* at 76.
19 *Id.*
20 CalCCA Opening Brief at 54-55; *see* CalCCA-102C at 3-4; *see also* 1 Tr.-C:180-184. (Lawlor/PG&E).
21 CalCCA Opening Brief at 54-55.

placed into service; thereafter those same resources only have short-term market value based on prices that can be recovered for the sale of limited Resource Adequacy (RA) volumes transacted in the short-term balancing market. [22]

- Implies that 100 percent of the resources in the utilities' portfolios could be replicated at these short-term prices – a conclusion that is unsupportable, as the Commission pointed out in its May 2017 Padilla Report.[23]

- If applied to utility-owned generation (UOG) operating costs, implies that UOG is being operated uneconomically.[24]

The use of this short-term capacity benchmark is also a signal to Energy Service Providers (ESPs) and Community Choice Aggregators (CCAs) that is counterproductive in the state's goals of decarbonization. It will drive these LSEs to maximize unbundled, short-term products rather than the new long-term resources that support state policies focused on long-term procurement to achieve renewable and reliability objectives.

For these reasons, as discussed in greater detail below, the capacity benchmark, when combined with the PD's proposed true-up, creates a cost shift from bundled customers to departing load customers. Recognizing the PD's efforts to find balance among perspectives, CalCCA proposes modification of the PD's capacity valuation by proportionate blending of the approaches proposed by the parties. While the approach departs from CalCCA's clear view that long-term values should be used to value long-term resources, a blended benchmark will provide a more reasonable approach than proposed by the PD.

A. The PD Errs in Concluding That Only Actual Market Revenues for Short-Term Sales Should Be Used to Estimate Capacity Value.

The PD markedly understates the value of capacity in the Joint Utilities' portfolios. The adopted approach would use a weighted-average value from the Energy Division's annual RA Report, although the PD is unclear about: (1) which value among the many presented in the report would be used, (2) whether and how long-term contracts will be incorporated into the weighted average, (3) how value should be attributed to RA Capacity in contracts whether other

22 CalCCA Opening Brief at 55.

23 *See* Exh. CalCCA-106 The Padilla Report: Costs and Savings for the Renewables Portfolio Standard in 2016 (Pursuant to Public Utilities Code Section 913.3), May 1, 2017 (2017 Padilla Report) at 12.

24 CalCCA Opening Brief at 57.

products are bundled with RA, such as energy and ancillary services available in tolling and battery storage contracts, or (4) how the value will be available for review and audit for reasonableness by the parties.

The Joint Utilities cited two numbers from the 2016 RA Report: \$24.24/kW-year[25] and \$37.20/kW-year.[26] It is readily apparent that these values are stale, unrepresentative of the broader market for all RA resources used for compliance, and inapplicable to future capacity valuation, given the extensive evidence in the record regarding diminishing surplus capacity because of retirements and contract expirations, rising capacity values, first-ever invocation of one CPM and RMR contracts for periods of a year or longer, and the planned imposition of a multi-year RA requirement. Extracting the values from the RA Report, regardless of which value, scrapes the "bottom of the barrel" for capacity price proxies, accounts for no more than 20 percent of the RA Capacity used for compliance[27] and does not reasonably represent the value of all of the capacity in the Utilities' PCIA-Eligible portfolios.

The range of values for capacity discussed in the proceeding and more recently made available through a PG&E advice letter demonstrate that capacity value can range from as low as \$24.24/kW-year[28] per kW-month on average for system RA, based on the 2016 RA Report, to \$124/kW-year when considering the weighted average of RA and CAM resources,[29] up to \$172 kW-year for PG&E's recent Moss Landing Battery Storage Project[30] or \$233 kW-year "cost of new entry" approach discussed by AReM/DACC.[31] Simply glancing at the chart below, which shows the wide range of possible capacity values, makes it evident that the PD's capacity value is unreasonable.

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25 Joint Utilities Rebuttal Testimony at Appendix E line 19 (first column), citing the \$2.10/kW-month (which converts to \$24.24/kW-year) average price for 2016-2020 NP-26 RA contracts from Table 7 of the 2016 RA Report.

26 Joint Utilities Opening Testimony at 2-19 and n. 35, citing the \$3.10/kW-month (which converts to \$37.20/kW-year) weighted-average price for all 2016-2020 RA contracts from Table 7 of the 2016 RA Report.

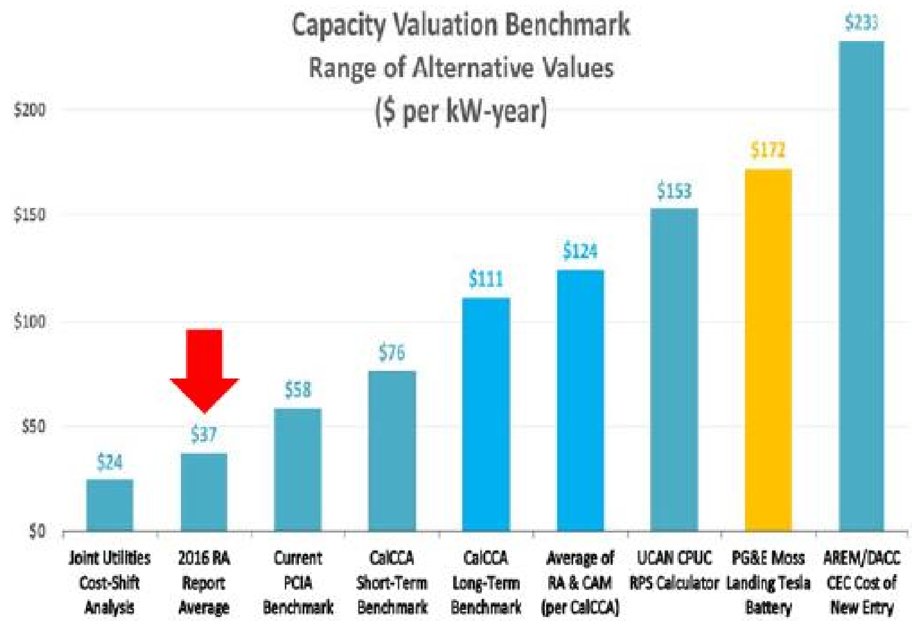
27 CalCCA Rebuttal Testimony at 2B-4. The 20% figure also excludes demand response, CAM, and RMR resources, further reducing the amount of capacity the values in the CPUC's RA Report represent.

28 *Id.* at 41.

29 CalCCA Rebuttal Testimony at 2B-5 and CONFIDENTIAL Exh. CalCCA 2B-A.

30 *See* PG&E Advice Letter 5322-E, June 29, 2018

31 Exh. AREM/DACC 1-1 at 20.



The unreasonableness of this approach is bolstered by the Commission's own observations on the use of short-term prices for valuation. Rejecting the utilities' proposal to use short-term values to value their entire RPS portfolio, the Commission concluded:

> The CPUC's concern with the IOUs' approach is two-fold. First, few, if any resources in any of the large IOUs' portfolios would be considered cost-effective, including low-cost hydroelectric and nuclear resources. Second, the large IOUs' calculations are based on short-run avoided costs, and it seems unlikely that the large IOUs would be able to procure 20% or more of their portfolios accounted for by the RPS program under short-term contracts.[32]

In this same vein, the prices realized in short-term sales of excess RA capacity cannot fairly represent the value of the entire portfolio of capacity.

The Joint Utilities' own testimony also demonstrates that it would be unreasonable to rely on short-term prices for the entire portfolio value. Using these short-term prices to assess cost shifts is in conflict with the Joint Utilities' view that "a market does not exist that would provide additional revenues to compensate for the full capacity value of post-2002 UOG resources."[33] In addition, the utilities' operation of

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32 Exh. CalCCA-106, 2017 Padilla Report at 12.
33 Exh. IOU-1 at 5-9:21-23.

their own generation demonstrates a higher value, as Mr. Kinosian, on behalf of CalCCA, explained:

> A higher value for capacity from PCIA-eligible resources is revealed through a comparison of those resources' operating costs with the current PCIA benchmark. PG&E continues to operate its fossil facilities (Gateway, Colusa and Humboldt), and its nuclear facility (Diablo Canyon), despite those facilities having avoidable, incremental costs of operation that are significantly above the current combined PCIA benchmark for energy and capacity.[34] *Based on the 2018 ERRA cost forecast and PCIA benchmark value*, PG&E's fossil plants are not cost-effective to operate in 2018. Diablo Canyon operating costs are forecast to be $878 million compared with a PCIA benchmark value of $728 million (energy and capacity), for net uneconomic operating costs of $150 million. Likewise, PG&E's fossil generation fleet is forecast to have a variable operating cost of $334 million compared with a benchmark value of $286 million, leaving $48 million of uneconomic operating costs.[35]

He concluded that the incremental, avoidable cost incurred by PG&E and SCE to provide RA from their fossil and nuclear resources was well above the current RA proxy of $58/kw. Either these plants are uneconomic to continue to operate or, more likely, the existing capacity benchmark – even the higher benchmark under the existing methodology -- understates the value of the resources in the portfolios.[36]

Finally, PG&E has acknowledged the additional value to the capacity held in the portfolio.[37] By retaining excess capacity, the utility essentially has insurance to avoid non-compliance penalties, by retaining a "buffer" of excess RA until compliance is certain. It also avoids the possibility of having to backfill when they experience a shortfall and thus avoid price risk. These and other benefits identified accrue to bundled customers regardless of any sale of short-term capacity.

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[34] Avoidable costs exclude all costs associated with existing sunk costs (depreciation, income taxes and return on rate base), and include only costs of continuing operation (fuel, O&M, A&G, new capital additions).

[35] CalCCA Rebuttal Testimony at 2B-5-6 (emphasis added).

[36] The high ongoing RA costs of UOG resources should be expected as the current RA benchmark is based on the minimum generic incremental cost of providing RA from a utility-owned fossil plant.

[37] *See supra* n. 14.

B. Assigning a "Zero" Value to Any Unsold Capacity in the Utility Portfolio Is Unreasonable.

TURN proposes to assign a "zero" value to capacity remaining in the utility portfolio. It is not clear whether TURN meant this to apply to *all* untransacted capacity or only that capacity determined to be "excess" to bundled customer needs. And, if the latter was intended, TURN provides no criteria for determining what portion of capacity is excess.

TURN's position not only lacks clarity; it is wrong. Even if a product is not sold in the short-run, the underlying resource maintains long-term value (or, if not, the utility should not be retaining the resource in the portfolio).[38] The resource may have been held for use by bundled customers in either the instant or a future period, to avoid non-compliance with RA requirements, to provide a "buffer" for bundled customers or to mitigate price risk. Moreover, if the Joint Utilities continue the practice of maintaining "buffers" to protect bundled customers until the last moment possible for a sale, assigning this excess a zero value very patently shifts costs from bundled customers to departing load customers. In essence, the portfolio product can be used by the bundled customers as insurance and require departing load customers to bear the economic consequences of that use.

Assigning a zero value also presumes that the utility's decisions regarding which products to sell and when to sell them are completely neutral and reasonable. The record in this proceeding, as the PD notes, should make the Commission uncomfortable in this regard.[39] Neither SCE nor PG&E even attempted to sell excess portfolio products on a long-term basis to maximize product value until very recently[40] (in the shadow of this proceeding). And policing their choices on what, when and how to sell "excess" capacity would be a material challenge.

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38 *See supra* n. 14.

39 Proposed Decision at 62.

40 4 Tr. 806:8-28-808:1-19 (Lawlor/Cushnie).

C. Relying Too Heavily on Market Prices Driven by Utility Sales Risks Benchmark Manipulation.

It is no secret that downward pressure on the PCIA benchmark makes it more difficult for non-utility LSEs to compete with the incumbent utility. The lower the benchmark value, the more costs are shifted to departing load customers. An incentive is thus present for the utilities to sell RA capacity in a manner that minimizes price – *e.g.,* offering only one month at a time, offering the capacity at an inopportune time in the market, or offering the capacity under less than optimal terms and conditions. Selling a limited amount of RA capacity at low prices could pay big dividends, shifting costs to departing load customers, if the limited number of short-term transactions is used to value 100 percent of portfolio capacity. The problem is further heightened to the extent utility transactions dominate the Energy Division's RA Report. The 2016 RA Report relies on 2,241 monthly contract values but does not specify how many of those contract values involve a sale by one of the Joint Utilities.[41]

Establishing a methodology for valuing capacity that relies heavily on short-term utility transactions places the utilities in a position of further depressing competition. For this reason alone, the RA Report is unsuitable as a proxy for all portfolio capacity.[42]

D. Proposed Composite Benchmark

The determination of a reasonable price for capacity is admittedly a challenge. The record makes abundantly clear, however, that choosing the value at the bottom of the barrel is unreasonable. For these reasons, CalCCA proposes, as a compromise, a composite alternative of capacity values as a transitional approach. As the PD contemplates, the composite benchmark should have separate values for system, local and flexible RA (although the PD does not address how to disaggregate these values from reported data).[43] Price referents should then be represented in the benchmark in proportion to the overall proportion of transactions they represent.

> *System RA.* The Energy Division RA Report's "85% of MW at or below" price for System RA would be selected and used in the weighted average System RA price calculation in proportion to the percentage of compliance products represented by the

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41 *See* Exh. CalCCA-109, 2016 Resource Adequacy Report, at 6.

42 CalCCA Opening Brief at 24.

43 For example, most purchases of Local RA also include the system RA attributes and the 2016 CPUC RA Report did not identify prices for Flexible RA.

> reported transactions. For example, if 25% of all system RA compliance requirements are met through these short-term transactions, the RA Report "85% of MW at or below" System RA price would be weighted 25% in the system RA capacity benchmark, while the remaining 75% of the System RA capacity would be valued at the short-run "going forward" operating costs of a combustion turbine, as valued by the CEC ("going forward" cost); this value is comparable to (albeit, still lower than) the avoidable cost the bundled customers incur for the provision of RA from UOG fossil resources.
>
> *Local RA.* The Energy Division RA Report's "85% of MW at or below" price for Local RA would be selected and used in the weighted-average Local RA price calculation in proportion to the percentage of compliance products represented by the reported transactions. If, for example, 25% of all system RA compliance requirements are met through these short-term transactions, the RA Report "85% of MW at or below" Local RA price would be weighted 25% in the Local RA capacity benchmark, while the remaining 75% of the Local RA capacity would be valued at the weighted average CAISO CPM price.
>
> *Flexible RA.* Because there are no clear, liquid benchmarks or referents for flexible capacity, all flexible capacity should be valued at the existing "going forward" RA benchmark.

CalCCA continues to believe that this approach – which remains a short-term approach pending development and implementation of observable and verifiable long-term valuation benchmark – will undervalue capacity and send the wrong signals to CCAs procuring capacity for their customers. If the PCIA benchmark signals that RA is worth only $24/kW-year, this benchmark should be consistently applied to all future Commission directed procurement activities such as energy efficiency, distributed generation, storage, and demand response programs. Such an approach, however, would clearly not help California achieve its long-term policy goals. Neither will it position CCAs, to be more aggressive in the acquisition of storage and other preferred resources.

IV. PREPAYMENT

The PD recognizes that a primary challenge associated with the PCIA is the volatility combined with lack of transparency. More specifically, it recognizes that the PCIA presents a great deal of financial risk to departed customers, discourages investment in long-term resources, and threatens departed customers with rate shock if their provider is unable to quickly adapt to tariff changes by IOUs. Because of this dynamic, departed load customers from a variety of customer types and business models advocated for, and the Proposed Decision recognized the value in, the ability for departing load customers such as CCAs to prepay their obligations. There is significant value to be gained by a known, one-time prepayment of charges.

The PD correctly concludes that "the solution that best fits the guiding principles articulated in the Scoping Memo is adoption of a prepayment option for departing customers." To implement this change, the PD recommends that (1) departed customers be permitted to pre-pay their PCIA obligations according to the terms proposed by AReM/DACC, and (2) the utilities be required to negotiate in good faith. Agreements concerning such prepayment would then be submitted to the Commission for review and approval via a Tier 3 Advice Letter.

While the PD heads in a positive direction, it is unlikely to succeed as written. The largest counterparty in these negotiations has shown an active unwillingness to consider prepayment - which is *already an option*. As AReM/DACC notes in its testimony, each utility already has in its New Municipal Departing Load tariff the option to have the PCIA and other departing load obligations paid as a negotiated lump sum.[44] The utilities even acknowledge that prepayment would provide certainty for their bundled customers as well.[45] However, departing load customers have not had any success in working with IOUs to make use of the existing provisions in IOU tariffs to cooperatively and voluntarily bargain in good faith with departing load customers that are actively interested in pre-payment. Without additional, specific *and* enforceable Commission direction, there is no reason to believe the IOUs will change their approach now.

In this proceeding, IOUs have refused to provide a forecast of departed load obligations and have argued against pre-payment even being *considered*. To now expect these same IOUs to develop a forecast and then negotiate in good faith in calculating terms of payment is unrealistic. To be successful, the Proposed Decision should be supplemented with a requirement that the utilities maintain on an ongoing basis a forecast of departed load obligations for each vintage of departed load. The utilities further should be required to offer a prepayment transaction, according to the terms specified by AReM/DACC, calculated using the forecast of obligations. As both IOUs and departed customers have a vested interest in protecting their customers, the Commission should take the opportunity to show leadership and balance the competing

44 Exh. AD-1 at IV.C 27-28.
45 Exh. IOU-3 at 7B-33

considerations in this arena by defining "indifference" in a manner that establishes up front standards that create a level playing field amongst each customer group that the Commission can then enforce where IOUs and entities with departing load are unable to reach agreement after good faith negotiation.

V. LONG-TERM SOLUTIONS

CalCCA appreciates the PD's direction to begin developing a long-term, voluntary market-based solution in a separate phase of this proceeding. Taking this approach will ensure that the Joint Utilities realign their supply with bundled load and optimize the monetization of their portfolios. The auction proposal advanced by CalCCA would also create a more reliable measure of market value that can be used to benchmark any ongoing stranded costs as the portfolios are adjusted. The PD does not go far enough, however, in establishing the scope of the solution, timelines and expectations for the process.

The PD states:

> We also open a second phase of this proceeding to consider the development and implementation of a comprehensive solution to the issue of excess resources in utility portfolios. We expect that solution to be based on a voluntary, market-based redistribution of <u>excess</u> resources in the electric supply portfolios of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.[46]

While a "voluntary, market-based redistribution" responds to several of the proposals offered in the proceeding to address the utilities' growing mismatch of supply and load, it unnecessarily limits the proposal to redistribution of "excess" resources. CalCCA's approach contemplated the sale and auction not just of "excess" resources, but of all RPS resources and GHG-free resources.[47] All LSEs pay the stranded costs for all of the resources in the Joint Utilities' portfolio, not simply the "excess" resources. Moreover, by unburdening the Joint Utilities' portfolio in this way, it frees the utility to reconstitute its portfolio to better meet bundled customers' requirements. Including the utilities among the potential purchasers, the auction process assures a more liquid market that will produce more meaningful and reasonably representative long-term market prices that are observable and verifiable. Finally, if the Commission truly believes that the value of the resources in the current portfolios is

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46 Proposed Decision at 3.
47 *See* CalCCA Opening Brief at 113.

approximated by the short-term market prices that will be developed under the PD's proposed benchmark, then it should give no credence to fears that the utilities will face increased costs if they dispose of resources in the auction but then are required to buy them back at market prices.

The Commission should provide more concrete guidance on this issue and others for the Phase 2 process. The guidance should:

- Eliminate the reference to "excess" resources in its Phase 2 directive, allowing exploration of the CalCCA auction alternative or any other alternative that brings to market more than just "excess" portfolio resources.
- Establish four guiding principles: (1) resources should be offered on a long-term basis; (2) utility portfolio resources should be sold to the market participants who most value the resources, thereby optimizing portfolio value; (3) utility portfolio contracts should be sold intact, where permitted under the terms of the existing agreement and where feasible given the size of the resource; and (4) resources that cannot be sold should be repackaged with terms and conditions that mirror the underlying resources, wherever possible.
- Require implementation of a portfolio sale process by January 1, 2020, as proposed by CalCCA.
- Require the implementation of a "reverse auction" in 2019 to explore opportunities for contract buydowns;
- Require the Energy Division to set an initial workshop to commence Phase 2 one month following the issuance of the final decision in this phase.

In a similar vein, the final decision should clarify that any concerns regarding utility portfolio management should be raised in a Forecast ERRA, to enable direction to the utility before imprudent portfolio management occurs.

VI. CONCLUSION

For the foregoing reasons, CalCCA requests that the Commission adopt the PD, subject to the modifications contemplated herein. Proposed Findings of Fact and Conclusions of Law are provided in Exhibit A.

Respectfully submitted,

EVELYN KAHL
Counsel to
the California Community Choice Association

August 21, 2018

EXHIBIT A

PROPOSED MODIFICATIONS

Findings of Fact

4. A revised RA Adder should be ~~that is~~ calculated with separate benchmarks for system, local and flexible RA to the extent feasible. The system RA benchmark should be calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions, in proportion to the percentage of total system RA used for compliance represented by such transactions. The remainder of the benchmark should be calculated using the CEC's short-term "going forward" calculation of capacity value. At this point in the development of flexible capacity values, the CEC's short-term "going forward" is the best available estimate of this value. Together, these components of an RA calculation will produce reasonably accurate estimates~~, if a zero or de minimis price is assigned for capacity expected to remain unsold~~.

19. A true-up mechanism will increase the accuracy of the PCIA cost allocation between bundled and departing load customers only where actual costs and revenues from transactions are available. A true-up of the portfolio value of resources remaining to serve bundled customers will not increase accuracy because there are no actual transactions through which to obtain an "accurate" value. The true-up thus should true up generation and purchase power costs, energy costs and any associated sale revenues. ~~ensure that bundled and departing load customers pay equally for PCIA-eligible resources.~~

~~20. The ratemaking proposal in Exhibit IOU-1 provides general concepts that can be used to implement an annual true-up process for the PCIA.~~

26. An option to prepay would provide simplicity and predictability for departing load customers, and greater certainty in the prepayment rights and obligations would benefit departing load customers.

28. A new phase of this proceeding would enable parties to continue working together to develop a number of proposals regarding portfolio optimization and cost reduction for future consideration by the Commission, including the sale of all or some portion of the IOUs' supply portfolios.

Conclusions of Law

4. The methodology for calculating the RA Adder adopted in D.06-07-030 and modified in D.07-01-030 should be changed to the method provided in Finding of Fact 4. ~~Appendix 1 of this decision.~~

16. A true-up mechanism consistent with Finding of Fact 19 should be adopted to ensure greater accuracy in PCIA cost allocation between ~~that~~ bundled and departing load customers ~~pay equally for PCIA-eligible resources~~.

19. A PCIA collar ~~with a floor and a cap~~ should be adopted to limit the change of the PCIA from one year to the next.

NEW. The IOUs should be required to maintain on an ongoing basis a forecast of departing load obligations for each PCIA vintage, which should serve as the basis for a default prepayment right that can be elected by departed customers.

25. A second phase of this proceeding should be opened in order to consider proposals for a "working group" process to enable parties to continue working together to develop proposals regarding portfolio optimization and cost reduction for future consideration by the Commission, including the sale of all or some portion of the IOUs' supply portfolios.

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ALJ/SCR/jt2 **Date of Issuance 9/20/2018**

Decision 18-09-013 September 13, 2018

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

DECISION APPROVING TRACK 1 SETTLEMENT

Summary

This decision addresses the unopposed joint motion for adoption of a settlement agreement entered into by Pacific Gas and Electric Company (PG&E), Center for Accessible Technology, Marin Clean Energy, the Office of Ratepayer Advocates, The Utility Reform Network, and Brightline Defense. The settlement agreement resolves issues regarding the current exemption from paying the Power Charge Indifference Adjustment (PCIA) for medical baseline customers taking energy from community choice aggregators (CCAs) in PG&E's service territory. The settlement agreement is approved. Medical baseline customers of CCAs that begin to serve residential customers subsequent to this decision will not receive the PCIA exemption. Payment of the PCIA by medical baseline residential customers of CCAs currently serving customers will be phased-in over a period of four years.

This proceeding remains open.

1. Background and Procedural History

The Commission opened this Order Instituting Rulemaking (OIR or Rulemaking) to review the current Power Charge Indifference Adjustment (PCIA). The PCIA that is in place today dates to statute enacted during the 2001 California energy crisis. Readers are directed to the Scoping Memo for this proceeding for a detailed history of the PCIA.

The Scoping Memo determined that Track 1 of this proceeding would review and possibly revise the status of exemptions from the PCIA for customers of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) who participate in the California Alternate Rates for Energy (CARE) and the Medical Baseline (MB) programs, and departing load customers in PG&E service territory who participate in the MB program. The Commission resolved those issues for SCE and SDG&E in Decision (D.) 18-07-009.

Pursuant to Rule 12.1(b) of the Commission's Rules of Practice and Procedure (Rules), the Settling Parties noticed and held a settlement conference on February 7, 2018. On March 28, 2018 PG&E submitted a motion (Joint Motion) on behalf of itself and Center for Accessible Technology (CforAT), Marin Clean Energy (MCE), the Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), and Brightline Defense (Settling Parties), requesting Commission approval of a settlement agreement (Proposed Settlement) that would resolve the issues regarding the MB exemption for customers in PG&E's territory. The Joint Motion is unopposed.

The CARE and MB programs provide a reduction in energy bills to participating customers. Customers are eligible to participate in CARE if they participate in certain public assistance programs or if their annual household income is below a certain threshold. Customers are eligible to participate in the MB program if they have special energy needs due to certain qualifying medical conditions. Settling Parties explain[1] that in Resolution E-3813, the Commission established an exemption from the PCIA for departing load CARE and MB customers in order to shield those customers from energy crisis-related costs resulting from the California Department of Water Resources (DWR) long term contracts, which were entered into on behalf of investor-owned utility (IOU) customers during 2000-2001. The IOUs recovered the costs of DWR contracts in customer rates, with the exception of CARE and MB customers. This exemption implemented the California Legislature's intent to shield all CARE and MB customers from energy crisis-related above-market costs. Settling Parties state that most energy crisis-related costs are no longer part of the PCIA. Instead, the above-market costs in IOU portfolios consist largely of long-term contracts and utility-owned generation. Settling Parties further state that all bundled service IOU customers--including CARE and MB customers as well as non-CARE and non-MB customers--pay for these above-market costs.

As recounted by the Settling Parties,[2] the Commission approved a settlement agreement in PG&E's 2007 General Rate Case application (Application (A.) 05-12-002) that eliminated the PCIA exemption for CARE customers taking energy from CCAs in PG&E's territory. The scope of the settlement did not include MB customers, who continued to receive the PCIA exemption. PG&E requested elimination of the PCIA exemption for MB customers taking energy

1 Joint Motion at 1-2.

2 *Id.* at 2.

from CCAs in Phase 2 of its 2017 General Rate Case (A.16-06-013), but the Commission removed the issue from the scope of that proceeding so that it could be considered in the instant proceeding.

The prehearing conference was held on August 31, 2017 and the Scoping Memo and Ruling of Commissioner Peterman issued on September 25, 2017. Parties subsequently 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 Rate Design Window proceeding, and PG&E's 2014 General Rate Case Phase 2, regarding Track 1 issues (i.e., the CARE and MB PCIA exemptions);
2. All the already-exchanged and then-pending data request responses in this proceeding regarding Track 1 issues; and
3. An opportunity for non-utility parties to submit responsive testimony on Track 1 issues.

Parties also reserved their rights to request evidentiary hearings in order to further develop the evidentiary record in this proceeding, but no party ultimately exercised that right.

On December 5, 2017 PG&E submitted another joint motion on behalf of itself, SCE, SDG&E, California Choice Energy Authority (CCEA), MCE, and CforAT (together, the Filing Parties) for entry into evidence of the prepared testimony and discovery responses listed above.[3] Pursuant to Rule 13.8(c), the Filing Parties moved that the following information be admitted into evidence:

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[3] CCEA is a joint powers authority that provides support services to CCA programs, including CCA programs administered by the cities of Lancaster, Pico Rivera and San Jacinto in southern California. MCE is an operational CCA in northern California. CforAT is an organization that is authorized by its bylaws to represent the interests of residential customers with disabilities before the Commission. The Filing Parties state that they also collaborated with additional

Footnote continued on next page

- Exhibit 1 Updated and Amended Prepared Testimony in PG&E's 2017 General Rate Case Phase 2, 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 2, A.16-06-013
- Exhibit 3 PG&E's Public/Non-Confidential Responses to CforAT Data Requests 001 and 002 in this PCIA OIR, R.17-06-026
- Exhibit 4 PG&E's Responses to MCE Data Requests 001, 002 and 003 in this PCIA OIR, R.17-06-026
- Exhibit 5 CforAT Responses to PG&E Data Request 001 in this PCIA OIR, R.17-06-026
- Exhibit 6 MCE Responses to PG&E Data Request 001 in this 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 this PCIA OIR, R.17-06-026
- Exhibit 9 SCE Responses to CforAT Data Request 001 in this PCIA OIR, R.17-06-026
- Exhibit 10 CCEA Responses to SCE Data Requests 001 and 002 in this PCIA OIR, R.17-06-026

The Commission granted the Filing Parties' joint motion in D.18-07-009.

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parties interested in this proceeding, including ORA, TURN, Western Riverside Council of Governments, Coachella Valley Association of Governments, and Los Angeles Community Choice Energy. Filing Parties state that these parties support or do not oppose the joint motion.

2. Positions of the Parties

The Scoping Memo identified the issues that would be resolved in Track 1 of this proceeding:

1. Should the PCIA exemptions for current departing load CARE and MB customers be eliminated?
2. Should CARE and MB customers of new CCA programs receive PCIA exemptions?
3. If the PCIA exemptions are eliminated, should the resulting PCIA for current departing load CARE and MB customers be phased in over a period of time?
4. If the PCIA exemptions are eliminated, should the Commission order the utilities to educate CARE and MB customers about how their bills will change?

Settling Parties state that although they did not serve testimony addressing the PCIA exemption, their positions prior to reaching settlement were as follows:

- PG&E proposed to equalize the discounts for bundled MB customers and CCA MB customers by eliminating the PCIA exemption in its entirety as of a date certain;
- ORA and TURN also supported equalizing discounts for bundled MB customers and CCA MB customers by eliminating the PCIA exemption;
- CforAT did not object to elimination of the PCIA exemption for CCA MB customers, but expressed concern about the resulting rate increases for these customers, contending that some customers would see rate increases of approximately 30%;
- ORA and TURN supported a phase-in period of the PCIA for existing CCA MB customers in order to mitigate rate shock;
- MCE expressed that if the PCIA exemption is to be eliminated for CCA MB customers, the PCIA should be phased in to ensure that customers currently receiving the exemption do not experience rate shock;

- Brightline Defense supported elimination of the PCIA exemption, but advocated for gradual phase-in of the PCIA to minimize financial impacts;
- All of the Settling Parties supported an education and outreach effort involving collaboration between the incumbent IOU and the CCA working collaboratively to educate customers about the rate changes before the PCIA phase-in begins; and
- MCE proposed that the education and outreach to customers should begin no later than 60 days before the phase-in commences, and should continue throughout the entirety of the phase-in process.

3. The Proposed Settlement

The Proposed Settlement resolves the issues and positions listed above in the following manner:

- For any CCA that begins serving residential customers on or after the date PG&E can begin charging the PCIA to MB customers, MB customers of that CCA will not receive the PCIA exemption.
- For CCAs that are serving residential customers as of the date PG&E begins charging the PCIA to MB customers, the full PCIA amount will be phased-in over a period of 4 years.
  - o As early as June 1, 2019, PG&E will begin to phase-in the PCIA for MB CCA customers in PG&E's territory. The applicable PCIA obligation expressed as a percentage of the full otherwise applicable PCIA obligation will be 25% in the first year, 50% in the second year, 75% in the third year, and 100% in the fourth year.
  - o During the phase-in period, any customer who begins service with the CCA and is a MB customer will pay the same percentage of the otherwise applicable PCIA obligation as existing MB customers of the CCA. That is, if the second year of phase-in is 2021, a new MB customer will owe 50% of the PCIA. PG&E is not changing any ratemaking mechanisms as part of this transition. Thus, as MB CCA contribution to PCIA is increased, bundled customer responsibility will be reduced.

The Settling Parties will develop an education and outreach plan to provide notice to customers who receive the exemption regarding the phase-in schedule.

4. Commission Review of the Proposed Settlement

The Commission has long favored the settlement of disputes. However, pursuant to Rule 12.1(d) of the Commission's Rules of Practice and Procedure, the Commission will not approve a settlement, whether contested or uncontested, unless it is found to be reasonable in light of the whole record, consistent with law, and in the public interest. Further, where a settlement agreement is contested, it will be subject to more scrutiny than an all-party settlement agreement. As noted above, the Proposed Settlement is not contested.

4.1. Is the Proposed Settlement Reasonable in Light of the Whole Record?

Settling Parties assert that the Proposed Settlement reflects a reasonable balance of the positions taken by the Settling Parties on the PCIA exemption issue because they had the opportunity through discovery and settlement discussions to better understand the impacts of the PCIA exemption on bundled MB customers and CCA MB customers.[4] Settling Parties agreed that (1) CCA MB customers and bundled CCA customers should receive the same discount, but (2) the increase to MB customer bills would be substantial so it made sense to phase in the PCIA in order to alleviate these increases.[5]

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4 Joint Motion at 5.

5 *Ibid.*

4.1.1. Discussion

We find that the Proposed Settlement is reasonable in light of the whole record. As noted above, the exhibits that constitute the record in this proceeding were submitted jointly by active parties, including some of the Settling Parties. The Settling Parties relied on that record in order to make the consensus-based proposal before us. Therefore, we find that the Proposed Settlement reasonably resolves the contested issue in Track 1 of this proceeding, specifically with respect to affected customers of CCAs in PG&E's service territory.

4.2. Is the Proposed Settlement Consistent with the Law?

The Settling Parties assert that equalizing the discounts for bundled MB customers and CCA MB customers by eliminating the PCIA exemption for CCA MB customers is consistent with the law because it prevents cost shifts to bundled customers resulting from departing load.[6]

4.2.1. Discussion

Public Utilities Code Section 365.2 provides that the Commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers, and that 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.

Public Utilities Code Section 366.3 provides that bundled retail customers of an electrical corporation shall not experience any cost increase as a result of

[6] *Ibid.*, citing California Public Utilities Code Sections 365.2, 366.3, and 366.3 [sic].

the implementation of a CCA program, and that 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.

We find that the Proposed Settlement is consistent with Sections 365.2 and 366.3.

4.3. Is the Proposed Settlement in the Public Interest?

Settling Parties contend that the Proposed Settlement is in the public interest. Settling Parties explain that although the phase-in means that the equal discount for all MB customers is not effective immediately, the Proposed Settlement results in all MB customers paying equally for above market RPS costs "in fairly short order," while also avoiding "overwhelming rate increases" for MB customers.[7]

4.3.1. Discussion

We find that the Proposed Settlement is in the public interest because it represents a compromise between parties who are in a position to weigh the competing interests of bundled customers (who would benefit from immediate cessation of the entire exemption) and CCA customers (who will benefit from phasing out the exemption). In this instance, we accept the results of that balancing exercise as presented to us by the Settling Parties.

[7] *Ibid.*

4.4. Conclusion

For the reasons discussed above, we find that the Proposed Settlement is reasonable in light of the whole record, consistent with law, and in the public interest. The Proposed Settlement should be approved.

5. Waiver of Comment Period

This is an uncontested matter in which the decision grants the relief requested. Accordingly, pursuant to Section 311(g)(2) of the Public Utilities Code and Rule 14.6(c)(2) of the Commission's Rules of Practice and Procedure, the otherwise applicable 30-day period for public review and comment is waived.

6. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and Stephen C. Roscow is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The March 28, 2018 Settlement Agreement is an uncontested settlement.
2. The March 28, 2018 Settlement Agreement was entered into by parties representing all impacted customer groups.

Conclusions of Law

1. The March 28, 2018 Settlement Agreement is reasonable in light of the record, consistent with law, and in the public interest.
2. The March 28, 2018 Settlement Agreement should be approved.
3. This is an uncontested matter in which the decision grants the relief requested. Accordingly, pursuant to Section 311(g)(2) of the Public Utilities Code

and Rule 14.6(c)(2) of the Commission's Rules of Practice and Procedure, the otherwise applicable 30-day period for public review and comment should be waived.

O R D E R

IT IS ORDERED that:

1. The Joint Motion of Pacific Gas and Electric Company, Center for Accessible Technology, Marin Clean Energy, the Office of Ratepayer Advocates, The Utility Reform Network, and Brightline Defense dated March 28, 2018 requesting approval of the Settlement Agreement among Pacific Gas and Electric Company, Center For Accessible Technology, Marin Clean Energy, Office of Ratepayer Advocates, The Utility Reform Network and Brightline Defense is granted. The Settlement Agreement attached to the Joint Motion is adopted.
2. Rulemaking 17-06-026 remains open.

This order is effective today.

Dated September 13, 2018, at San Francisco, California.

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	Rulemaking 13-09-011 (Filed September 19, 2013)

PETITION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON BEHALF OF THE WORKSHOP PARTICIPANTS FOR MODIFICATION OF DECISION 17-10-017'S ADOPTION OF STEPS FOR IMPLEMENTING THE COMPETITIVE NEUTRALITY COST CAUSATION PRINCIPLE

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Dated: **July 18, 2018**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	Rulemaking 13-09-011 (Filed September 19, 2013)

PETITION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON BEHALF OF THE WORKSHOP PARTICIPANTS FOR MODIFICATION OF DECISION 17-10-017'S ADOPTION OF STEPS FOR IMPLEMENTING THE COMPETITIVE NEUTRALITY COST CAUSATION PRINCIPLE

I.

INTRODUCTION

Pursuant to Rule 16.4 of the Commission's Rules of Practice and Procedure, Southern California Edison Company (SCE, U 338-E) submits this Petition for Modification (PFM) of Decision (D.) 17-10-017 (Decision). This PFM is filed within a year of the issuance of D.17-10-017. SCE submits this PFM on behalf of San Diego Gas & Electric Company (SDG&E, U 902-E), Pacific Gas and Electric Company (PG&E, U 39-M) (jointly, the Utilities), Marin Clean Energy (MCE), the Alliance for Retail Energy Markets (AReM), the Direct Access Customer Coalition (DACC), Sonoma Clean Power (SCP), the California Choice Energy Authority (CCEA), and the California Large Energy Consumers Association (CLECA) (collectively, the "workshop participants").[1] On June 27, 2018, the Energy Division held an initial workshop on

[1] Pursuant to Rule 1.8(d), representatives for SDG&E, PG&E, MCE, AReM, DACC, SCP, CCEA, and CLECA have authorized SCE to transmit and serve this PFM on their behalf.

implementation of competitive neutrality cost causation pursuant to Ordering Paragraph (OP) 4 of the Decision to develop consensus. The workshop was attended by representatives of Energy Division, the Office of Ratepayer Advocates (ORA), MCE, AReM, DACC, SCP, CCEA, CLECA, SCE, SDG&E, and PG&E. The workshop identified: (1) consensus topics on which agreement was reached; (2) non-consensus topics which required further discussion; and (3) topics that required further clarification and guidance from the Commission through a PFM process. To provide the workshop participants an opportunity to address the non-consensus topics, the Energy Division noticed a second workshop, which was held on July 11, 2018, and attended by the workshop participants identified above.

As a result of the workshop discussions, the workshop participants identified three areas requiring changes and clarification to the Decision in order to ensure an efficient implementation of the Decision's directives:

1. Changes to the definition of "affected customers" as described in Step Three's directive to the Utilities to send a letter to "affected customers" explaining the implementation of the competitive neutrality principle. Currently Finding of Fact (FOF) 20 defines "affected customers" as "the Competing Provider's customers to whom the Competing Provider will market the demand response program deemed similar."
    - This PFM requests a change to FOF 20 to define "affected customers" as only customers who are enrolled in the utility program, either directly or through an aggregator.
2. Consistent with the above change and D.14-12-024, this PFM requests a clarification in Step Four that the bill credit for cost recovery would go to **all** of the involved CCA/ESP's customers, not just those "affected customers" as defined in FOF 20 or in Step Three.
3. Confirm that the Utilities' obligation under Step Three to send letters by the 60th day to "affected customers" only requires the Utilities to send the notification

letter to their directly enrolled customers and the third-party DR providers/aggregators.

- This PFM seeks an explicit requirement in the Decision that the third-party aggregators are responsible for communicating with their customers.

II.

WORKSHOP PARTICIPANTS PROPOSE CHANGES TO D.17-10-017 TO ENABLE A MORE EFFECTIVE AND LESS CONFUSING IMPLEMENTATION OF THE COMMISSION'S COMPETITIVE NEUTRALITY COST CAUSATION DIRECTIVES.

Several of the workshop participants noted that the discussions of the Step Three letter at pages 27 and 28 of the Decision varied in the description of who should receive the letter. The Step Three discussion on page 27, and in Attachment 1 to the Decision, references the customers of the Community Choice Aggregation (CCA) or the Energy Service Provider (ESP) who are in the utility's DR program determined to be similar to the CCA/ESP DR program, as the "affected customers". Then, on page 28, the Decision states that the letter should go to the "affected customers" who are the CCA/ESP's customers to whom that provider will market the demand response program(s) deemed similar. In addition, Finding of Fact (FOF) 20 defines "affected customers" as the CCA/ESP's customers to whom it will market the demand response program deemed similar.

Extensive discussion led the workshop participants unanimously to conclude that the letter described in Step Three should only go to the CCA/ESP customers who are enrolled in the utility's similar program, either directly or through an aggregator. Trying to identify to whom the CCA/ESP would market their similar DR program was problematic and the workshop participants agreed that sending the letter to all the CCA/ESP's customers to make sure all potential CCA/ESP participants were covered would create confusion and potential misunderstanding.

In order to implement the solution supported by the workshop participants, the Decision needs to be modified to identify clearly that the letter in Step Three only goes to CCA/ESP customers enrolled in the utility's similar DR program, directly or through an aggregator. To achieve this, the workshop participants propose to modify FOF 20, as set forth below in strike-out and underlined font.

> **FOF 20:** **<u>For purposes of the letter described in Step Three</u>**<u>,</u> affected customers are defined as the Competing Provider's customers **<u>who are enrolled in the Competing Utility's</u>** ~~**to whom the Competing Provider will market the**~~ demand response program deemed similar, **<u>either directly or through an aggregator</u>**. **<u>The definition in this finding of fact shall not apply to Step Four</u>**.

The change to FOF 20 would apply to clarify the description of "affected customer" in Step Three to refer only to the CCA/ESP's customers who are in the utility's similar DR program, and not to the CCA/ESP customers to whom the CCA/ESP will be marketing.

Consistent with the proposed modification to FOF 20 for the definition of "affected customers," the workshop participants also seek a modification to Step Four of Attachment 1 of the Decision to ensure that the bill credit is provided to <u>all</u> customers of the CCA or ESP involved.[2] In fact, D.14-12-024, which established the competitive neutrality cost causation principle, specifies that result.[3] Moreover, Finding of Fact 11 in D.17-10-017 clearly anticipated that all of the CCA's or ESP's customers would receive the bill credit.[4]

The proposed revision to FOF 20 presented above would limit the definition of "affected customers" to customers who would receive the Step Three notification letter. Without modification, the current definition of "affected customers" in FOF 20 could limit the credit to the CCA/ESP's customers "to whom the Competing Provider will market its demand response program deemed similar." If the existing or proposed change to FOF 20's definition of "affected customers" were to describe who receives the credit under Step Four, the CCA/ESP's customers

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2 Step Four is also described on page 28 and notes that "affected customers shall receive a bill credit for the similar program(s)".

3 D.14-12-024, Ordering Paragraph 8b, emphasis added: "Once a direct access or community choice provider implements its own demand response program, the competing utility shall, no later than one year following the implementation of that program: i) ***end cost recovery from that provider's customers*** for any similar program …"

4 FOF 11 reads: "The Commission should require the use of the bill credit on Competing Provider's customers' bills to end cost recovery of the Competing Utility's similar demand response program."

to whom the CCA/ESP does not market or those customers not currently enrolled in a utility DR program, would not get the bill credit. The workshop participants agreed that result would be inequitable, inconsistent with the intent of the Decision and would violate the requirements established in D.14-12-024, as explained above. The workshop participants request modification of Step Four in Attachment 1 (and on page 28 of the Decision) as follows:

> **Step Four:**
>
> Within one billing cycle following the end of the cost recovery and targeted marketing by the Competing Utility to the Competing Providers' customers of the similar demand response program(s), ~~**affected**~~ **all** customers **of the CCA/ESP identified as the Competing Provider** shall receive a bill credit for cost recovery of the similar program(s).

III.

WORKSHOP PARTICIPANTS REQUEST CHANGES TO D.17-10-017 TO CONFIRM THE COMPLIANCE OBLIGATIONS OF THE IOUS AND THE THIRD-PARTY DR AGGREGATORS WHEN COMMUNICATING TO CUSTOMERS

Step Three requires the letter to "affected customers" to go out by the 60th date after the date of the Commission resolution determining that a CCA/ESP DR program is similar to a utility program.[5] To the extent "affected customers" are in aggregator portfolios, the utility will need to include the aggregators in the process, to enable them to work with their customers who will lose eligibility for the utility's similar program, and to address collateral impacts, such as possible effects on the composition of their CAISO resources. In the joint-Utilities' January 30, 2018 filing,[6] the Utilities agreed to send letters to participants directly enrolled in utility DR programs and to the third party aggregators, but noted their position that third-party DR

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5 The Decision does not specify whether the letter should be sent in hard copy or electronically. PG&E, SCE and SDG&E interpret the Decision as allowing either hard copy or electronic transmittal of the letter, especially since some customers identify electronic communications as their preferred method of communication with their utility.

6 *See Pacific Gas and Electric Company's, San Diego Gas & Electric Company's, and Southern California Edison Company's Proposed Approach to Determine Cost Refunds to Eligible Community Choice Aggregator and Direct Access Customers*, filed January 30, 2018, at p. 6.

aggregators would be responsible for further communicating with their customers about the CCA/ESP DR program deemed similar and their removal from the IOU DR program.

The Utilities' position is consistent with Commission precedent where the Commission has acknowledged that aggregators have the relationship with their customers. Specifically, in its *Decision Adopting Guidance for Future Demand Response Portfolios and Modifying Decision 14-12-024*, the Commission held: "Because aggregators are the direct contact for customers in aggregator programs, it is the responsibility of the third-party aggregator to provide such notification and outreach."[7] In addition, in a recently issued Final Resolution approving the Utilities' prohibited resources restrictions for DR programs, the Commission held: "We agree with SCE that requiring coordination with aggregators on outreach creates an additional unnecessary administrative burden, inconsistent with the existing guidance in tariff and contract language. Because aggregators are the primary contact for customers in aggregator programs, they bear the sole responsibility to conduct customer outreach."[8] Consistent with Commission precedent, the Utilities proposed that a notification letter to the aggregators would fulfill their 60th day compliance obligation under Step Three. Thus, this PFM seeks explicit confirmation that the utility's notification to the aggregators fulfills their compliance obligation. The proposed changes needed for Step Three, Attachment 1, are set forth below.

Step Three:

> If the outcome of the resolution determines that the Competing Provider's proposed demand response program is similar, the Competing Utility has 30 days from the issuance of the resolution to begin the process to cease cost recovery by and targeted marketing to the Competing Provider's customers of the similar program. By the **60th** day, a letter shall be sent to the affected customers notifying them of the change. The letter will also explain to customers of the Competing Provider currently enrolled in the Competing Utility's similar demand response program that they will cease to be eligible for that program at the end of the year, but will be eligible to participate in the Competing Provider's similar demand response program. No later than 365 days following the issuance of the resolution, the Utility shall complete the changes.

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7 *See* D.16-09-056 at p. 33.

8 *See* Resolution E-4906 (issued June 21, 2018), at p. 80.

The Utilities shall comply with this directive by sending a notification letter to their directly enrolled customers and a notification letter to the third party aggregators. The third party aggregators shall communicate to their customers the pending changes.

IV.

CONCLUSION

The workshop participants agreed that proposed revisions to the Decision will enable a more effective and less confusing implementation of the Step Three letter. In addition, the revisions in this PFM would align the Decision language with provision of the bill credit to all the CCA/ESP customers who pay the utility demand response authorized costs in distribution rates.

Respectfully submitted,

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July 18, 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.	**R.17-09-020** **(Filed September 28, 2017)**

RESPONSIVE COMMENTS OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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August 8, 2018

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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.	**R.17-09-020 (Filed September 28, 2017)**

**RESPONSIVE COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

Pursuant to the Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge (ALJ), issued on January 18, 2018 (Scoping Memo), Decision 18-06-030 (Track 1 Decision) and the email ruling of ALJ Allen, dated August 1, 2018 (August 1 Ruling), the California Community Choice Association (CalCCA) submits these Responsive Comments. As directed by the August 1 Ruling, the July 10, 2018, Prepared Direct Testimony of Witnesses Lorenzo Kristov, Richard McCann and Shehzad Wadalawala on behalf of the California Community Choice Association (CalCCA Testimony), is attached at Exhibit A.

I. INTRODUCTION

CalCCA supports adoption of a multi-year Local Resource Adequacy (RA) requirement for all load serving entities (LSEs) that are subject to Commission jurisdiction for purpose of RA requirements. CalCCA offers a Transition Proposal, which addresses the Commission's objectives, maximizes LSE self-provision of Local RA and leverages existing processes to facilitate timely implementation. The Transition Proposal relies on continued California Independent System Operator (CAISO) procurement of Essential Reliability Resources (ERRs) under its existing backstop procurement authority with an additional "residual" volume of procurement for needed resources that are not procured competitively by LSEs. By encouraging multi-year contracting, however, CalCCA expects that the Commission will reduce the need for CAISO intervention. In the longer run, CalCCA proposes a strategy that entails coordination among the Commission, the CAISO and stakeholders to remove local area constraints through deployment of transmission solutions and preferred resources.

While parties' have approached the issues in this proceeding with different visions, all parties are aligned on certain goals: reducing costs for ratepayers, facilitating the deployment of cost-effective preferred resources to address local constraints and reducing the degree of market power that underlies the need for solutions in Local Capacity Area (LCA) sub-areas. No doubt parties also align on promoting solutions that avoid administrative complexity. With all of these common goals, CalCCA submits that parties are capable of some degree of consensus through a workshop and comment process.

Consistent with the August 1 ruling, CalCCA identifies key issues, proposes a process for addressing these issues and suggests topics for further workshops. In addition, these comments highlight three perspectives that merit attention in setting the stage for a solution. First, CalCCA explains why concerns about FERC intrusion should not drive the solution in this Track. Second, these comments explain why a "residual" buying framework, rather than full central buying, will reasonably address the Local RA problems and will most effectively promote achievement of state policy goals at the local level. CalCCA offers a preliminary analysis of the magnitude of the problem to support this view in Exhibit B. Third, CalCCA, with reference to Pacific Gas and Electric Company's (PG&E's) analysis, explores why the CAISO is best suited among the available alternatives to serve as central buyer in a residual buying framework.

II. PROCEDURAL RECOMMENDATIONS

A. Recommended Process

CalCCA supports the use of a workshop and comment process to establish the multi-year resource adequacy (RA) framework. This process will enable the development of additional data to fully inform potential solutions and permit parties to explore consensus. CalCCA proposes two to three workshops to address the topics identified in Section II.C., which should be transcribed, recorded or summarized in an Energy Division Staff workshop report. Parties should then have an opportunity to file post-workshop comments and reply comments to integrate their initial testimony, responsive comments, subsequent proposals, workshop findings and stipulations. Assuming timely scheduling of additional workshops, CalCCA recommends providing for comments and replies using the existing briefing schedule of September 19 and October 5. Assuming no remaining issues of fact remain, the Commission will be positioned to issue a proposed decision based on this record.

While CalCCA believes at this time that the issues can be resolved through the effective use of workshops, the Assigned Commissioner and ALJ should not foreclose hearings until parties have had the opportunity to explore the issues described below in Section II.B. Requests for evidentiary hearing, if any, should be made in parties' post-workshop comments.

B. Scope of Issues

The Scoping Memo and the Track 1 Decision focused this Track on two primary issues. The Track 1 Decision directed that parties propose "a multi-year local resource adequacy requirement with a three-to-five-year duration," including a central buyer structure.[1] In addition, the Track 1 Decision identified transparency as a Track 2 issue, acknowledging proposals for transparency of RA contracting data[2] and the use of an electronic bulletin board for RA transactions.[3] Potential issues for consideration in either Track 2 or 3 included demand-response issues[4] and potential changes in the current planning reserve based on updated Effective Load Carrying Capacity ELCC runs conducted in the prior RA proceeding.[5] While each of these issues is important, CalCCA recommends limiting the scope of issues in Track 2 to a multi-year Local RA requirement featuring central buying and reserving all other identified issues to Track 3. Limiting the number of issues will increase the possibility of a timely decision adopting a multi-year requirement.

Within the multi-year requirement scope of issues, the testimony and workshop process thus far has identified the following key sub-issues:

1. What term would be most effective for a multi-year requirement?
2. What should the procurement target be for each year?
3. Should Local Capacity Areas (LCAs) be disaggregated, and for what purposes *(i.e.,* LSE procurement requirements or cost allocation)?

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1 Track 1 Decision, Ordering Paragraphs 10 & 11 at 54.
2 *Id.* at 44.
3 *Id.* at 45.
4 *Id.* at 47.
5 *Id.* at 40.

4. Would a framework where a central buyer procures all Local RA (central buying) or one where a central buyer procures only a residual volume (residual buying) be more effective?
5. How can LSE self-provision of Local RA be integrated with central or residual buying?
6. What type of entity should serve as the central or residual buyer?
7. What type of market mechanism should be employed by the central or residual buyer?
8. How can a central or residual buying framework address load migration?
9. What level of transparency is necessary regarding LCAs to inform efficient LSE procurement?
10. Should the compliance year continue to commence on January 1 or be shifted to commence on April 1?
11. When should the multi-year requirement commence?

CalCCA submits that another central issue has received insufficient attention. The record provides little information on the magnitude of the problem – the potential for an LCA sub-area deficiency -- underlying the drive for a multi-year requirement. Assessing the size of the problem requires an understanding of the scope of Essential Reliability Resources (ERRs) in each sub-area. If the amount of ERRs and other resources with market power is a relatively limited share of the LCR in each area, a limited, residual buying framework solution seems in order. If, instead, the number and location of resources prevents competitive procurement of a significant majority of resources in most or all LCAs, a more comprehensive solution may be required.

CalCCA provides a preliminary discussion of the issue in Section III, which concludes that a residual procurement framework is appropriate, but requests further development The analysis should be further explored in a workshop.

In addition, the discussion thus far lacks an adequate understanding of how supply-side and transmission solutions would be evaluated in any central buying framework. The CAISO applies economic criteria in assessing transmission solutions and has begun, in the 2018 transmission planning process (TPP), to compare transmission with supply-side solutions for LCA reliability needs. Likewise, the investor-owned utilities (IOUs) have economic and other criteria they apply in evaluating LCA solutions. A recent transaction that could provide a useful illustration of the process is PG&E's decision to procure nearly 600 MW of energy storage for terms of 10-20 years, submitted in Advice Letter 5322-E. Ultimately, any central buyer – including a special purpose entity - will be required to apply well-defined criteria in evaluating alternatives. These criteria and their application should be made transparent and considered in the process of designing a multi-year solution.

C. Workshop Topics

In light of the range of issues that must be addressed to develop a workable solution, CalCCA recommends two or three additional workshops. Topics should include:

- The nature of the underlying problem, including the scope of ERRs and other non-competitive resources.
- The central buying concept, including (1) the relative benefits of a central vs. residual buying structure; (2) the role of LSE self-provision and

existing commitments in any such framework and (3) the required characteristics of a central buyer and the suitability of the utility, special purpose entity or California Independent System Operator to fulfill that role.

- Cost allocation for centrally procured resources, including the implications for sharing costs with publicly owned LSEs, and for resources procured by CCAs and ESPs, which do not have access to assured recovery through the cost allocation mechanism (CAM) or power cost indifference adjustment (PCIA).
- Market mechanisms that can be used in the central buying process, including measures and enforcement for market power mitigation and procedures for comparing supply-side and transmission solutions to relieve local constraints.
- Adjusting in multi-year procurement targets for inherent historic bias in load forecasts used for resource procurement.

The workshops should permit interested parties to present proposals on each included issue, and should be recorded. A workshop report, prepared by the Energy Division with the assistance of interested parties, should be produced following the last workshop. Alternatively, the workshops should be transcribed.

III. INITIAL RESPONSES TO DIRECT TESTIMONY

During the August 1 prehearing conference, Assigned Commissioner Randolph and ALJ Allen invited not only procedural comments, but comments on any substantive matters raised in the July 10 testimony and the July 19 Energy Division workshop. While

CalCCA does not intend in these comments to provide a full response to initial testimony, three observations merit further discussion in advance of workshops. First, a central focus in this proceeding, whether explicit or implicit, is the perceived risk (or in some parties' views, perceived benefits) of broadening of FERC jurisdiction over California's capacity market. CalCCA explains below why a fear of FERC intrusion should not drive the solution in this Track. Second, a residual buying framework, rather than full central buying, will reasonably address the Local RA problem and will most effectively promote achievement of state policy goals at a local level. CalCCA offers a preliminary analysis of the magnitude of the problem to support this view in Exhibit B. Third, the CAISO is best suited among the available alternatives to serve as central buyer in a residual buying framework.

A. Concern That Limited Expansion of the CAISO's Procurement Role Could Result in FERC Interference with California Policy Goals Is Overstated.

The Track 1 Decision asks how a central buyer structure could "balance economic procurement criteria with other essential state policies, such as greenhouse gas emissions reduction targets and consideration of impacts on disadvantaged communities."[6] Underlying the statement is a concern that Federal Energy Regulatory Commission (FERC) involvement in California's capacity market, through the California Independent System Operator (CAISO), would result in price-optimized solutions, ignoring other critical state policy goals. Indeed, the Track 1 Decision notes TURN's express concerns

[6] D. 18-06-030 at 33.

that reliance on the CAISO could invite FERC intervention and impair the state's ability to achieve its policy objectives[7] – a concern reiterated in TURN's July 10 testimony.[8]

While achieving state policy goals should be the key non-economic driver guiding a solution in this Track, fear of FERC intervention should be put in its place. The decision in this Track carries little potential to move FERC to materially broaden its role in California's capacity markets. In fact, only one proposal, from Shell Energy North America (Shell), suggests it could invite FERC interference with California's important policy objectives.[9] The real and much more substantial risk of jurisdictional incursion is already present in the form of a recent complaint filed at FERC by CXA La Paloma, LLC, which requests expansion of FERC jurisdiction far more broadly than the local capacity market.[10] In fact, in light of this complaint, it is more likely that placing the IOUs at the center of Local RA procurement, further reducing the CAISO's role, could catch FERC's interest and slow progress toward the state's objectives. In other words, undue centralization is more likely to backfire in limiting FERC's role.

Reserving a meaningful but limited role for the CAISO not only mitigates the risk of broader FERC intervention, it offers other benefits. Namely, maximizing the opportunity for LSE self-provision enables CCAs to serve their intended purpose in driving the state's energy policy at the local level.

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[7] *Id.* at 31.

[8] Direct Testimony of Kevin Woodruff on behalf of The Utility Reform Network Regarding Track 2 Issues, July 10, 2018 (TURN Direct) at 3-4.

[9] Prepared Testimony of Michael Evans on behalf of Shell Energy North America (US), L.P. on Track Two Resource Adequacy Proposals, July 10, 2018 (Shell Direct Testimony) at 11.

[10] CXA La Paloma, LLC v. CAISO, FERC Docket EL18-177-000, filed June 19, 2018.

B. Residual Buying Is the Best Solution for a Limited Problem and Will Best Support the Achievement of California's Policy Goals

1. A Residual Buying Framework Is a Right-Sized Solution Given the Scope of the Problem.

While the nature and magnitude of the Local RA problem is highly relevant in formulating a solution, nothing in the record today sheds light on the issue. Shehzad Wadalawala, on behalf of CalCCA, prepared a preliminary analysis of this issue, which is attached as Exhibit B. The analysis strongly suggests that a residual buying solution, rather than full central buying, is best suited to address a limited problem and offers observations on the need for disaggregation of LCAs.

The Track 1 Decision describes a central buyer as "the solution most likely to provide cost efficiency, market certainty, reliability, administrative efficiency, and customer protection." Within this premise, CalCCA recognized the role of the central buyer to procure for two primary purposes. First, any efficient procurement solution should select all those resources that are essential, *i.e.* ERRs if not procured by any LSEs. These resources necessarily have local market power and a central buyer with the ability to mitigate local market power, *e.g.,* the CAISO. Second, the central buyer should have an opportunity to procure a residual amount, excluded from the CPUC's allocated local requirement, to efficiently select resources in sub-areas that are needed and are not addressed by the procurement of ERRs or through bilateral contracting by LSEs.

Exhibit B presents a preliminary analysis answering two key questions:

(1) How many resources have significant local market power, *i.e.* are ERRs?

(2) How significant is the risk of inefficient procurement that could result in collective deficiencies?

Throughout the discussion, the analysis presents observations and possible recommendations on how to ensure the continued success of the Local RA program.

The analysis suggests that nature and magnitude of the problem varies among the the three IOU territories. SDG&E has relatively simple sub-areas and few opportunities for inefficient procurement. Even a modest amount of residual procurement by a central buyer would ensure that all sub-area requirements would be met. Conservatively, ERR and residual procurement in the SDG&E service territory could be limited to roughly 290 MW, or 7.2 percent of the LCR.

SCE, while more complicated than SDG&E, still has fairly straightforward sub-areas. With respect to addressing local area reliability and market power, the Santa Clara sub-area within the Big Creek/Ventura Local area necessarily needs more resources or transmission upgrades. In the short term, all ERRs should be maintained while addressing such needs in the longer-term should necessarily be part of the IRP and/or TPP. With respect to inefficient procurement, given the high level of competition, a viable option is disaggregating both Local RA areas or placing some limitation on how much can be procured in any particular sub-area. As a result, there would be little opportunity for inefficient procurement resulting in collective deficiencies. With this change, even a modest level of residual procurement by a central buyer should be sufficient for SCE's service territory. Conservatively, on a combined basis, ERR and residual procurement in the SCE service territory could be limited to roughly 1226 MW, or 15 percent of the LCR in the LA Basin, and 621 MW, or 23 percent, in the Big Creek/Ventura sub-area.

PG&E is the most challenging because of the level of local market power. Inefficient procurement in the Ames/Pittsburg/Oakland LCA sub-area could result in a deficiency of 1741 MW, or 51 percent of the LCR. Inefficient procurement in Other PG&E Areas could drive a deficiency of 1670 MW, or 28 percent of the LCR. In the short term, all ERRs should be maintained. Beyond that, disaggregation of the local areas may be problematic given the concentration of market power. However, to maintain aggregated local areas for the purposes of compliance and to limit market power necessarily increases the likelihood of collective deficiencies. In the long-term, addressing such market power should fall into the purview of the IRP and/or TPP.

CalCCA looks forward to comments on this preliminary analysis and exploration of these issues through a workshop coordinated with the topic on the relative merits of a central and residual buyer.

2. A Residual Buying Framework Will Promote Implementation of State Policy Goals at a Local Level

Beyond providing a solution appropriately sized to the problem, a residual buying approach best advances California's policy goals by providing latitude for CCAs to implement those goals through local measures.[11] A central buying approach, in contrast, limits CCAs' efforts to promote resource development in their local areas (or the local areas of other LSEs) by increasing the risk of independent procurement aimed to meet LCRs.

Residual procurement is more likely to lead to the development of new resources than central procurement. PG&E proposes that a central buyer procure resources for no more than five years,[12] which is far too short to provide incentives to build new resources. And while the Staff Proposal is less clear on this point, it provides no

[11] Pub. Util. Code §366.2(a)(5).
[12] *See, e.g.,* PG&E Direct Testimony at 1-1:31.

assurances that an LSE's choice to develop or procure a new resource for a much longer term – ten years or more – would be procured by the central buyer, nor whether it would be accepted for a term of more than three to five years. In contrast, letting LSEs procure their own local resources, subject to clear and transparent criteria provided through the Transmission Planning Process, is more likely to lead to the development of resources requiring a secure, long-term commitment for financing. Finally, residual procurement does no harm to any LSE's existing Local RA position, enabling them to retain and build on their current resource portfolio subject to residual and backstop procurement.

Established CCAs are demonstrating their intent to develop and encourage smaller, local preferred resources that will promote California's goals. For example, Sonoma Clean Power implemented its ProFIT feed-in tariff (100% RPS) to procure local RPS-eligible resources of less than 1 MW for contract terms of 10 or 20 years.[13] Small, specialized resources to meet the needs of these programs typically carry a premium over other RPS compliance resources. Additionally, MCE recently brought online its MCE Solar One project, which is a 60 acre, 10.5 MW solar project in Richmond, CA capable of providing enough renewable electricity to serve approximately 3,900 MCE customers annually.[14] Whether these resources provide Local RA or not, the point is that barring CCAs from explicitly procuring Local RA or being credited for the Local RA attributes

[13] https://sonomacleanpower.org/profit-program/.

[14] http://napavalleyregister.com/news/state-and-regional/mce-celebrates-completion-of-giant-solar-farm/article_988338af-5499-595f-a1a0-b2e60446c78e.html; http://www.4-traders.com/CENERGY-HOLDINGS-32089807/news/Cenergy-sPower-complete-10-5-MW-solar-tracking-project-in-California-25894188/.

of local resources they procure will limit the ability of CCAs to maximize their contribution to achieving California's policy goals.

These observations point to an element of the present debate that deserves to be highlighted. Although the debate is framed as an objective, evidence-based comparison of alternatives, its underlying basis is philosophical. On the one hand, the Commission and the Energy Division Staff assert that California's environmental and policy goals, as well as efficient assurance of electric system reliability, cannot be achieved without centralized procurement under the direction of the Commission through their agents, the IOUs or a new state entity. On the other hand, CalCCA believes that California's goals cannot be achieved without the active engagement of CCAs and the local governments that create them. This view is reinforced by the growing determination shown by California local governments and communities to take more responsibility for their own energy needs, as a means to reduce environmental impacts, implement innovative electrification programs, achieve climate action adaptation plans and spur local economic development.

Much of the concern about CCAs with regard to California policy goals and local reliability needs stems from the fact that the CCA is a relatively new type of entity in the state and does not have a decades-long track record. Centralized procurement by the IOUs under Commission-authorized procedures, in contrast, is well-established and therefore is assumed to be less risky compared to decentralized energy and capacity procurement tied to local government planning. As such it can be tempting to assume also that CCAs and the local governments that create them are less concerned with and dedicated to statewide environmental goals and reliability needs, that they will tend to strive only to minimize procurement costs as if they were only concerned with profit maximization. This is simply not a fair, accurate or constructive assumption.

In fact, we have recent immediate evidence in how local agencies can effectively carry out state goals in water policy. In May 2015, the State Water Resources Control Board adopted Resolution No. 2015-0032 which imposed restrictions to reduce water use by local agencies by 4 to 36 percent depending on their circumstances.[15] Northern California agencies were to reduce usage by 16.2 percent on average, while Southern California utilities were to reduce by 22.5 percent.[16] In the end, Northern California utilities far exceeded their target with a 23.3 percent reduction, and Southern California's just missed theirs with an average of 21.4 percent. These agencies are much further disaggregated than CCAs, yet they were able to achieve the state's standards with sufficient coordination.

CalCCA urges the Commission to consider an alternative to the philosophical divide that appears to motivate the more extreme positions taken in this proceeding, and to view CCAs as partners with the Commission and the larger stakeholder community in achieving California's major policy goals while ensuring system reliability. The CalCCA proposal is designed with such a collaborative approach in mind. Thus it combines a Transition Program that can address current Local RA issues and needs alongside a Long-Term Strategy to target local preferred resources to reduce Local RA needs, with emphasis on procurement opportunities for CCAs and other LSEs. CalCCA is seriously

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[15] State Water Resources Control Board Resolution No. 2015-0032 to Adopt an Emergency Regulation for Statewide Urban Water Conservation, https://www.waterboards.ca.gov/board_decisions/adopted_orders/resolutions/2015/rs2015_0032.pdf, May 5, 2015.

[16] Mehdi Nemati, Steven Buck and David Sunding, "Cost of California's 2015 Drought Water Conservation Mandate," *ARE Update*, Vol. 21, No. 4, Mar/Apr 2018, pp. 9-11.

concerned that any approach that suppresses or pre-empts CCA procurement or prevents an LSE from realizing the full value of the resources it procures will ultimately impede progress on California's important climate, energy and social equity goals.

C. The CAISO is Best Suited to the Role of Central Buyer within a Residual Framework.

1. Nearly All Parties Contemplate a Continuing CAISO Procurement Role

Direct testimony reveals a broad spectrum of views on CAISO, and thus FERC, involvement in Local RA procurement. Shell anchors one end of the spectrum, proposing a FERC-regulated centralized capacity market (CCM). Shell acknowledges that a CCM "could interfere with the Commission's ability to promote preferred resources and advance the State's GHG emission reduction goals under SB 350." [17] Second, Calpine Corporation (Calpine) [18] and NRG Energy, Inc. (NRG)[19] also incorporate CAISO-administered markets into their proposals, but note that the proposals would permit significant volumes to be transacted bilaterally. [20] Encouraging a high level of bilateral transactions, subject to state policy directives or other incentives, would provide a meaningful opportunity and the most effective vehicle to meet state policy goals. CalCCA proposed in direct testimony the transitional involvement of CAISO and a marginal expansion of its role as a "residual buyer," within an existing tariff

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17 Shell Direct Testimony at 11. Mr. Evans observes that "[i]t will be difficult to avoid FERC regulation with a CCM, which involves the purchase and sale of capacity on a wholesale basis…." *Id.* at 8.

18 Testimony of Matthew Barmack on Behalf of Calpine Corporation, July 10, 2018 (Calpine Direct Testimony) at A-1. Calpine "explicitly acknowledges and expands the CAISO's current role as a 'central buyer,'" relying on CAISO's Competitive Solicitation Process (CSP) and Capacity Procurement Mechanism (CPM).

19 Prepared Testimony of Brian D. Theaker on behalf of NRG Energy, Inc., July 10, 2018 (NRG Direct Testimony) at 9.

20 *Id.* at 27; Calpine Direct Testimony at A-3.

framework, while maximizing LSE bilateral procurement. Even Susan Tierney, on behalf of the Joint Utilities, acknowledges that the CAISO "might end up needing to play a larger role to assure resource adequacy in the state" if the Commission cannot expand its role to include publicly owned utilities (a highly unlikely outcome given the need for legislative intervention).[21] She concludes that the long-term changes proposed by the Joint Utilities "would need to be crafted in a way that can gain approval by the FERC for those aspects of the approach that would fall under its jurisdiction under the Federal Power Act."[22] Finally, the Commission Staff Proposal anchors the other end of the spectrum from Shell, aiming to reduce or eliminate the need for CAISO backstop and placing Local RA procurement in the hands of the IOUs under the Commission's jurisdiction.

Pragmatically, the CAISO will have to retain residual procurement capability. If LSEs or a state-jurisdictional central buyer fails to procure ERRs through multi-year contract negotiations, the CAISO is the buyer of last resort. No other entity can serve this purpose since the CAISO, as a FERC-regulated entity, has the authority to direct procurement on a cost-of-service basis. No matter how robust a state-centered central buying framework may be, CAISO involvement cannot be avoided, and therefore FERC will always be involved. The question is how to leverage that jurisdiction best to achieve State goals.

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[21] Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, Long-Run Resource Adequacy Construct, Prepared Testimony, July 10, 2018 (Joint Utilities' Direct Testimony), Attachment 2 at 2-17.

[22] *Id.*

2. The CAISO Remains Best Suited to Address Local RA Procurement Concerns as a Residual Buyer

Three categories of potential full central buyers (central buyers) or residual central buyers (residual buyers) are proposed in direct testimony: the IOUs, a special purpose entity (SPE) or the CAISO. Staff proposes to designate an "independent arm" of the IOU act as central buyer for Local RA procurement for all LSEs,[23] and TURN supports reliance on the IOUs for this purpose.[24] PG&E, for its central buyer, and SDG&E, for its residual buyer, propose a special purpose entity (SPE).[25] Many parties envision a continued role for the CAISO, whether a dominant role (Shell, NRG and Calpine), a residual role[26] or a backstop role. CalCCA submits, and PG&E appears to agree, that the CAISO best suits the need for central buying until California can relieve the local area constraints through either transmission projects or non-wires alternatives (NWA).

PG&E produced a useful table comparing central buyer options and their relative benefits.[27] It compared the relative benefits in terms of reliability, affordability, market power mitigation, fair cost allocation, adaptability, and administrative simplicity. In PG&E's own analysis, only the CAISO provides benefits in all identified categories. The only real concerns PG&E raises with respect to the CAISO is "whether it would be willing to serve in that role, and the need for substantial conforming changes to be made

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23 Staff Proposal at 15.

24 TURN Direct Testimony at 3.

25 PG&E uses the term "Designated Purpose Entity" (DPE). PG&E Testimony at 2-20 – 2-21. PG&E suggests the DPE would be non-CPUC jurisdictional (PG&E Testimony at 2-X), while SDG&E contemplates an SPE "subject to regulatory oversight by the Commission."

26 [CalCCA]

27 PG&E Direct Testimony, Table 2-1 at 2-20.

to the CAISO tariff….”[28] Strikingly, the IOU was the least desirable central buyer, with challenges in six of the nine identified categories of benefit. While this approach, in PG&E's estimation, could eliminate underprocurement in LCA sub-areas, reduce backstop procurement and permit comparison of transmission alternatives with NWAs, it fails in the following areas by PG&E's own admission:

- FERC market power mitigation authority;
- Allocates costs to all market participants;
- Adaptability scalable to any degree of LSE;
- Eliminates iteration with CAISO on transmission studies;
- Secure contract financing for buyer;
- Eliminates contentious and costly procurement and resource management review

CalCCA generally agrees with the analysis presented in PG&E's Table 2-1. The table fails to identify, however, two other issues that likewise leave IOUs as the last choice for central buying. First, the IOUs' financial incentives are naturally biased in a way that presents a conflict of interest. Resource procurement to meet local requirements competes with transmission solutions. Because IOU shareholders would earn nothing from their central procurement role, but could be benefitted by transmission development as a participating transmission owner (PTO), it will be difficult for the IOUs to be neutral in performing the central role.

Second, there needs to be a sturdy "wall" between the department of the IOUs' procuring for bundled customers and the department operating as central buyer.

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[28] *Id.* at 2-21:5-9.

Otherwise, bundled procurement would be advantaged by gaining access to additional market and technical intelligence earned through procurement on behalf of all LSEs. To completely wall off these two departments would require the central buyer to have a full staff to serve this relatively limited function, which may not be feasible or cost-effective.

While CalCCA agrees with PG&E and others that an SPE is preferable to an IOU central buyer, a separate SPE is complex and could fall within FERC jurisdiction. PG&E correctly observes regardless of whether the "Designated Procurement Entity" is a state agency or private entity, enabling legislation would be required.[29] Moreover, any SPE that would buy and resell capacity would be operating in the wholesale market and would be subject to FERC jurisdiction. While PG&E points to the New York State Energy Research and Development Authority (NYSERDA) as an example of a state agency SPE, the agency is not an appropriate model for an SPE to buy and resell Local RA products. NYSERDA does not sell energy or capacity, but provides programs and services to the state and buys and sells Renewable Energy Credits and Zero Energy Credits. By staying in the credit realm, it avoids FERC jurisdiction. An SPE that engaged in Local RA purchases, however, would buy capacity and would have to sell the capacity and associated energy somewhere – to other LSEs or generally into the market. Under these circumstances, the agency would be subject to FERC wholesale jurisdiction. If administrative ease and avoiding FERC regulation are goals, an SPE – whether a state agency or other entity – is not the right choice.

CalCCA agrees with PG&E's conclusion that the greatest benefits lie in having the CAISO serve as a central buyer. As noted above, nearly all stakeholders contemplate

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[29] PG&E Direct Testimony at 2-22:6-9.

some role for the CAISO, whether central, residual. or backstop. Moreover, the two challenges identified by PG&E – the CAISO's willingness and the need for tariff changes – may be surmountable under CalCCA's Transition Proposal. While PG&E correctly observes the CAISO's reluctance to serve as a central buyer, the CAISO may have less concern if it remains in the "residual" position – procuring only ERRs and a small and declining balance of residual procurement. Moreover, while tariff modifications may be required to marginally broaden the current backstop role to include the "residual", these tariff modifications seem far less onerous than legislation for an SPE and establishing a new IOU department with adequate business separation from transmission and bundled procurement.

IV. CONCLUSION

CalCCA supports a workshop and comment process to resolve the issues in this Track and looks forward to opportunities to find areas of consensus with other interested parties. To promote further development of a workable solution, CalCCA requests additional workshops on the issues identified in Section II.C.

Respectfully submitted,

EVELYN KAHL
Counsel to
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August 8, 2018

Exhibit A

**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.	**R.17-09-020 (Filed September 28, 2017)**

**PREPARED DIRECT TESTIMONY OF WITNESSES
LORENZO KRISTOV, RICHARD MCCANN AND SHEHZAD WADALAWALA
ON BEHALF OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

TRACK II ISSUES

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Section **Page**

List of Acronyms

CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CCA	Community Choice Aggregator or Community Choice Aggregation
CPM	Capacity Procurement Mechanism
DA	Direct Access
DER	Distributed Energy Resources
DR	Demand Response
DRP	Distribution Resources Plan
EE	Energy Efficiency
ERR	Essential Reliability Resource
ESP	Electric Service Provider
FERC	Federal Energy Regulatory Commission
GAM	Green Allocation Mechanism
IDER	Integrated Distributed Energy Resources Proceeding
IEPR	Integrated Energy Policy Report
IOU	Investor Owned Utility
IRP	Integrated Resource Plan Proceeding
LCA	Local Capacity Area
LCR	Local Capacity Requirement
LSE	Load Serving Entity
OTC	Once-Through Cooling
PCIA	Power Charge Indifference Adjustment
PPA	Power Purchase Agreement
PTO	Participating Transmission Owner
RA	Resource Adequacy
RFO	Request for Offer
RMR	Reliability Must Run
RPS	Renewables Portfolio Standard
UDC	Utility Distribution Company
UOG	Utility Owned Generation

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.	**R.17-09-020** **(Filed September 28, 2017)**

PREPARED DIRECT TESTIMONY ON BEHALF OF THE THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

I. INTRODUCTION AND EXECUTIVE SUMMARY

California's continued leadership in setting and achieving critical targets for reducing greenhouse gas emissions and moving to clean energy is of global importance. Leadership is also critical to the health and safety of all Californians – both present and future – a point highlighted by the already visible impacts of the changing climate. Local communities have embraced the state's call for local action by forming community choice aggregators (CCAs) to build on state efforts. Continued success in achieving the state's emissions reduction and clean energy targets depends on continuing the evolution of California's regulatory programs and policies, including resource adequacy (RA) program rules and procurement structures.

The need to evolve the RA framework is driven primarily by three key changes. Fossil-fired and nuclear power plants that have long played a role in grid reliability are retiring, sometimes before alternative clean energy solutions can be implemented. In addition, the growth of diverse distributed energy resources (DER) is making it harder to forecast net demand, set Local RA requirements and to determine how those requirements will be met. Finally, the transition of the Commission-jurisdictional retail market from a few large investor-owned utilities (IOUs) to an increasing number of smaller load-serving entities (LSEs) increases the need for the Commission's coordination of LSEs' efforts in meeting RA requirements.

The most recent annual RA compliance cycle for 2018 emphasized the importance of the greater coordination in meeting Local Capacity Requirements (LCRs). In the PG&E Transmission Access Charge (TAC) area, there was a 1,071.76 MW total deficiency due to sub-area constraints while individual LSE deficiencies totaled 72.23 MW.[1] The shortfall required supplemental backstop procurement by the California Independent System Operator (CAISO), leading to collective overprocurement of Local RA and unnecessary costs for ratepayers.

The Commission responded to these challenges[2] in its Track 1 Decision, D.18-06-030, directing stakeholders to propose multi-year Local RA programs and central buying for at least some portion of Local RA. The Track I Decision, along with the Scoping Memo and recent Customer Choice *en banc* hearing, highlight key objectives and issues that must be addressed to respond effectively to the evolving RA landscape:

- ✓ Ensuring sufficient resource availability to maintain required and expected levels of system reliability;
- ✓ Avoiding collective overprocurement of Local RA and mitigating unnecessary ratepayer costs;

1 CAISO Evaluation Report of Load Serving Entities' Compliance with 2018 Local and System Resource Adequacy Requirements, November 13, 2017.

2 The Commission also responded directly to the CAISO's backstop procurement for 2018 through Resolution E-4909, issued on January 11, 2018, authorizing PG&E "to hold a competitive solicitation for energy storage and preferred resources to address two local sub-area capacity deficiencies and to manage voltage issues in another sub-area." The Resolution contemplated that this procurement would result in "lower overall ratepayer costs." Resolution E-4909 at 1.

- ✓ Preserving LSE procurement preferences for local, clean resources to meet RA requirements;
- ✓ Allocating the cost of meeting LCRs equitably among LSEs;
- ✓ Mitigating planned and unplanned resource retirement, which has resulted in out-of-market backstop procurement by the CAISO;
- ✓ Reducing market and regulatory uncertainty, which is leading to stagnation of new preferred resource build-out to replace retiring resources;
- ✓ Realigning scale between buyers and sellers (large existing assets and smaller LSEs);
- ✓ Increasing the transparency of market information to ensure efficient and economic procurement of needed Local RA resources;
- ✓ Mitigating market power (total and partial) in local capacity areas (LCAs)
- ✓ Decarbonizing the electricity sector by addressing California's goals to eliminate gas-fired generation, reducing the impacts on Disadvantaged Communities (DACs), and leveraging trends in DER growth.

Immediate progress on many of these issues can be made through near-term implementation of a transitional multi-year Local RA program that will ensure local reliability while mitigating impacts on ratepayers. A more comprehensive long-term planning and deployment process is also needed, however, to reduce reliance on fossil-fuel generation[3] and address other broader policy goals.

Based on these considerations, CalCCA proposes a two-phase approach to addressing local reliability needs. The multi-year-forward Transition Program would begin in 2019 for compliance in 2020 and beyond. The Transition Program relies on a rolling three-year forward Local RA procurement requirement for all LSEs, in

[3] CalCCA understands that some existing fossil-fuel resources may still be needed for system flexibility even after they are no longer needed for local-area reliability. CalCCA anticipates that the long-term strategy proposed here can and will be targeted to obviate these needs as well by facilitating development of flexible preferred resources.

compliance with the Track I Decision, aimed to address the shortcomings identified with the existing program. In parallel, the proposed Long-Term Strategy coordinates LSE procurement (consistent with Integrated Resource Plan (IRP) and RA obligations) with the CAISO transmission planning process (TPP) to deploy preferred resources to address local constraints. Together, these actions will enable the Commission and stakeholders to address all key issues and provide an orderly transition from our present capacity fleet to a carbon-free capacity fleet, thereby ensuring grid reliability, minimizing ratepayer costs and accelerating achievement of California's climate goals.

A. Summary of CalCCA's Proposed Transition Program

CalCCA's Transition Program envisions (i) a three-year Local RA procurement obligation for LSEs, (ii) greater transparency of reliability needs in local sub-areas, and (iii) a centrally procured residual Local RA amount in each LCA. Under the program, greater sub-area transparency, along with the Commission's coordination of LSE procurement and central buying, ensures meeting 100 percent of Local RA requirement for Year 1 and 95 percent and 80 percent for Years 2 and 3, respectively. These objectives would be met through assignment to each LSE of its proportionate share of the net local capacity requirement (Net LCR) for each LCA. Net LCR is the load-forecast-based Total LCR from the CAISO LCR studies reduced by:

1) The proportionate share of the Total LCR to be procured by Publicly Owned Utilities (POUs) within the LCA; and

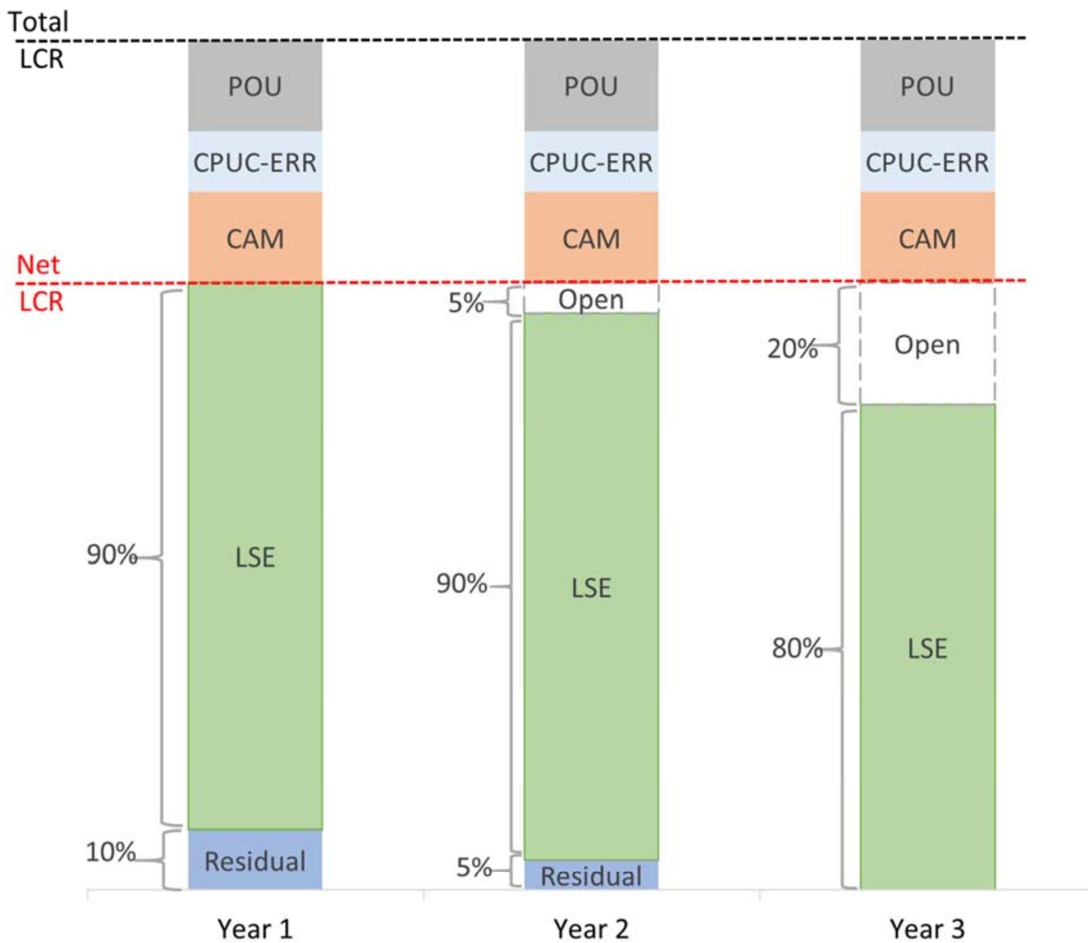
2) The CPUC Jurisdictional LSEs' share of expected procurement of "Essential Reliability Resources" (ERR) – resources for which there are no substitutable resources[4] – identified by the CAISO as necessary to address LCA or sub-area requirements; and

[4] CalCCA proposes that any pivotal supplier in a sub-area, *i.e.* a resource some of whose capacity will be needed even if all other resources in the sub-area are procured for their full

3) The Commission's allocation to LSEs of resources under the Cost Allocation Mechanism (CAM) and any other allocation of Local RA resources held in the IOUs' portfolios.

LSEs in Years 1 and 2 of the three-year RA cycle must procure 90 percent of their shares of the Net LCR for each LCA with the remainder procured by a Central Buyer. For Year 3 LSEs must procure 80 percent of their Net LCR shares.

Figure 1: Illustration of 3-Year Rolling Forward Local Capacity Transition Program



capacity, is necessarily an ERR. Further, if a resource is determined to be pivotal supplier in Year 2 or Year 3 but not preceding years (most likely due to planned plant retirements in the sub-area), it should also be designated as an ERR in all preceding years to ensure it does not retire prematurely.

To ensure proper incentives for LSEs to invest in new carbon-free resources to meet their requirements and relieve constraints, the LSE's Year 2 and 3 obligations can be met with newly contracted resources under certain conditions, as discussed in Section III. Section III explains how LSE procurement and Central Buyer procurement together achieve the Local RA needs on a rolling annual basis. It also describes all the steps of the Transition Program. Appendix A provides a detailed time line.

CalCCA proposes that the Central Buyer bear ultimate responsibility to procure the ERRs, with an opportunity in advance of this procurement for LSEs to meet or beat the CAISO's Capacity Procurement Mechanism (CPM) Soft Offer Cap (SOC). The Central Buyer would also be responsible to procure the Residual Need, defined as 10% of the Net LCR for Year 1 and 5% of the Net LCR for Year 2.

CalCCA recommends that the CAISO serve as Central Buyer for the ERRs and the Residual Need, as defined in this testimony. By leveraging the existing procurement mechanisms authorized to the CAISO by the Federal Energy Regulatory Commission (FERC), specifically the CPM and Reliability Must Run (RMR), with certain refinements explained later herein, the Transition Program is best positioned for success. Designating the CAISO as residual Central Buyer:

- Minimizes wholesale market jurisdictional conflicts between the Commission and FERC,[5] preventing potentially more sweeping market reform by FERC;

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[5] Examples of potential jurisdictional conflicts include FERC-directed capacity market design, as FERC's rejection of the PJM ISO capacity market proposal (FERC, "Order Rejecting Proposed Tariff Revisions, Granting In Part And Denying In Part Complaint, And Instituting Proceeding Under Section 206 Of The Federal Power Act," Docket Nos. EL16-49-000 et al, June 29, 2018), and Complaint of CXA La Paloma, LLC to FERC, submitted June 20, 2018, asking for creation of a central buying authority for the CAISO to resolve its issues.

- Leverages the CAISO's existing tools, which would not be available to any other Central Buyer, to mitigate local market power of FERC-jurisdictional wholesale generators;
- Permits the use of the CAISO's cost allocation tools to ensure that all LSEs – including POUs and other LSEs outside the scope of Commission authority – pay for needed LCA resources;
- Avoids exacerbating the growing mismatch between the IOUs' supply portfolios and their bundled demand; and
- Avoids the need to create yet another complex regulatory structure within California's electricity market.

Only the CAISO as Central Buyer can meet these objectives.

Two additional issues require consideration. First, as the Commission contemplated in the Scoping Memo, transparency into sub-area requirements will better enable all procuring parties to achieve program objectives.[6] Three-year forward forecasts regarding ERR requirements and CAM resources are a critical foundation to transparency. Transparency of other information will also be important to enable LSEs to understand sub-area dynamics such as resource effectiveness and the performance requirements for potential substitute preferred resources. Second, the Transition Program must be coordinated with market sales of excess Local RA in the IOUs' portfolios, such as those under consideration in R.17-06-026, to enable LSEs collectively to achieve cost-effective compliance.

B. Summary of CalCCA's Proposed Long-Term Strategy

CalCCA's Long-Term Strategy proposal, described in detail in Section III of this testimony, is designed to complement the Transition Program proposal by substantially reducing or eliminating LCA sub-area issues and Local RA needs. This will be achieved

[6] Citation to relevant section

primarily through LSE procurement of local preferred resources, thus reducing the need for substantial CAISO procurement of fossil-fuel ERRs. To achieve this desired end state, CalCCA proposes that the Commission adopt its stated goal, and provide a structure and incentives for all LSEs (including CCAs), the IOUs (as PTOs and distribution utilities as well as LSEs), developers of clean energy resources and other stakeholders to collaborate in developing cost-effective alternatives to transmission solutions identified in the TPP for reducing local grid constraints.[7]

The TPP uses the CEC IEPR demand forecast as a crucial input. This allows a full accounting for California's evolving demand for electricity and how it will be affected by the projected growth of load modifiers (including energy efficiency, electric vehicle and rooftop solar adoption). The TPP planning assumptions also reflect scheduled power plant retirements (*e.g.,* once-through-cooling plants and Diablo Canyon) and scheduled in-service dates of approved transmission upgrades. Thus, the TPP would be the process, as it is today, for describing local reliability needs in sufficient detail to inform design of effective solutions, identifying transmission solutions to meet the needs, and evaluating proposed alternatives to determine the preferred solution.

The Long-Term Strategy builds on two ongoing trends and processes. First, the ongoing growth of DERs is already reducing the need for reliability transmission upgrades, as evidenced by the recent cancellation or downsizing of transmission upgrades

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[7] The Oakland Clean Energy Initiative described in the CAISO 2017-18 Transmission Plan (pp 128-129) is a successful example of such a process. http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf

that were previously approved based on expected future reliability needs.[8] The proposed strategy would build on this growth by targeting additional preferred resource procurement by LSEs to offset LCRs, coordinated with the IRP process. Second, in April 2018 the CAISO announced a transmission study plan for the current 2018-19 planning cycle aimed to reduce or eliminate Local RA needs in certain LCAs with fossil resources. The CalCCA proposal would strengthen the impact of this effort by fostering opportunities for stakeholders to propose non-wires alternatives (NWA) or alternative transmission solutions (ATS), focused first on alternatives to eliminate fossil-fuel generation located in DACs.[9]

The Commission must play a coordinating role in the Long-Term Strategy to ensure that IOUs' distribution resource plans (DRP) consider the full value of DERs, including load management measures, and that the needed preferred resource development is integrated across the DRP, IRP, IDER, the CEC IEPR and the CAISO's transmission plan. It must also resolve critical policy issues needed to ensure fair and accurate compensation to local resources.

The success of CalCCA's proposed Transition Program and Long-Term Strategy depend on collaboration and coordination among all LSEs, the Commission, the CAISO,

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[8] "Efficiency, DERs saving $2.6B in avoided transmission costs, CAISO says," *Utility Dive*, https://www.utilitydive.com/news/efficiency-ders-saving-26b-in-avoided-transmission-costs-caiso-says/519935/ , March 26, 2018. See CAISO 2017-18 Transmission Plan, pp 2-3.

[9] An NWA is an electrical asset or set of assets that substitute for a transmission solution but are not themselves considered transmission assets. They are typically resources procured for energy and RA capacity by an LSE, and may be interconnected at either distribution or transmission level. A related but distinct concept is an ATS, which is an electrical asset or set of assets that substitute for a transmission solution and are compensated as transmission assets, owned by a PTO and operated as part of the CAISO controlled grid. The attractiveness of the ATS is its ability to earn all or part of its cost recovery as a rate-base grid asset. A solution to meet local reliability needs without a transmission upgrade could involve an NWA or an ATS or a combination of the two, but currently only the NWA construct is open to DERs.

the Energy Commission and the participating transmission owners. The Commission is in a pivotal position to ensure this success through its administration of the Transition Program and coordination of the Long-Term Strategy through the IRP, IDER, DRP and other planning processes.

II. THE EVOLVING CHALLENGES OF ENSURING LOCAL AREA RELIABILITY

Conditions for ensuring local grid reliability are changing, and changes are required in the mechanisms used to meet this objective. The key drivers of these changes include (1) the growth in DER resources, (2) the increasing number of LSEs in the market and (3) the impending retirement of fossil-fuel resources. Even without these new challenges, Local RA procurement has occurred under challenging conditions: (1) the complexity of local grid topology and operations, which creates locationally granular resource needs, and (2) local market power on the part of certain resources within the local areas for which there are no current alternatives (*i.e.*, no competition).[10] Under these conditions, some backstop procurement may be needed even when all LSEs fully meet their Local RA procurement requirements – a problem that arose for the 2018 RA compliance year. Any proposed Local RA solution must thus directly address these conditions.

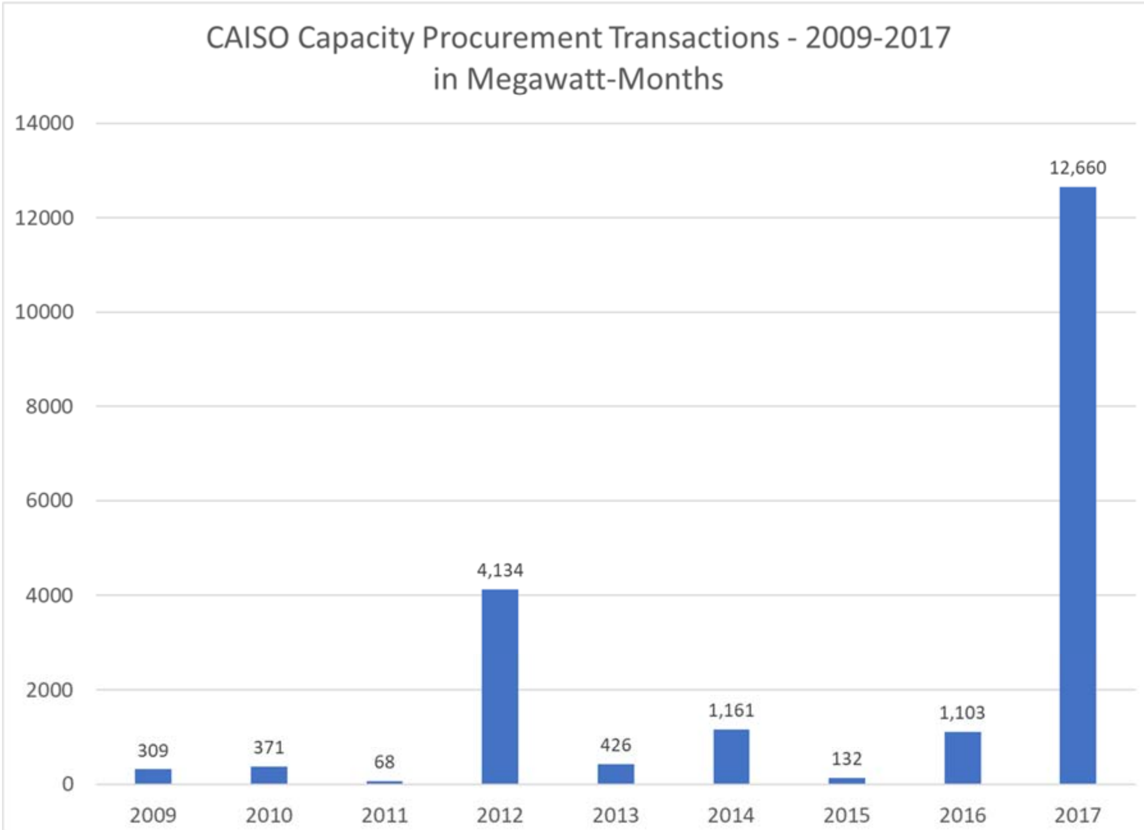
[10] Because the transmission constraints that drive local capacity needs pre-date the formation of wholesale power markets in California, the market power of essential local resources has been an issue since the start-up of the CAISO in 1998. The reliability must-run (RMR) mechanism has been the FERC-approved means to procure such resources at mitigated cost-of-service prices since the beginning of California's electricity market reform.

A. Changing Market Dynamics

In the context of Resource Adequacy, a Local Capacity Area (LCA) is a portion of the CAISO-controlled transmission grid characterized by a need for supply resources located within the area to meet the demand within the area. The need for local supply resources arises due to one or more transmission grid constraints into or within the LCA that prevent the area from fully relying on importing power from elsewhere in the grid to meet demand. These conditions are most prevalent where there are high levels of in-area demand and when contingency events take some grid facilities out of service. Thus, in principle, needs for local-area resources could be eliminated by upgrading the transmission grid in those areas. Until recently, however, existing local resources have met the needs and local transmission upgrades have not been deemed to be needed or cost-effective. The Local RA requirements have ensured that LSEs procure the needed local resources, on an annual basis prior to each compliance year, at reasonable cost under most circumstances, with rare need for backstop procurement by the CAISO.

Figure CCA-2, below, illustrates the amount of CPM capacity procured by the CAISO from 2009 to 2017. Even with the substantial increase in 2017 (largely due to issuing one-year agreements instead of one to two months which had been standard previously), this amounts to about 1,050 MW on average each month compared to a system wide peak of 50,116 MW.

Figure CCA-2



Going forward, any local reliability mechanism must meet the challenges presented by fossil resource retirement, DER growth and the increasing number of LSEs serving the retail market. Existing fossil-fuel generators have traditionally met a major share of the local-area needs. The desire to rely on these resources, however, is declining due to the state's focus on decarbonization and the elimination of once-through cooling (OTC) generation. While transitioning towards a carbon free fleet, economic trends challenge the financial viability of resources that are needed in the interim. In addition to power plant retirement, DER growth complicates planning any local reliability solution. While DER development initially accelerated through deployment of rooftop solar photovoltaic (PV) resources, DER potential is more diverse due to the success of California's programs promoting storage, electric vehicle charging, dispatchable demand

and more. These resources add complexity in demand forecasting and quantifying LCR. DER also presents jurisdictional issues – with the local area transmission constraint arising under one jurisdiction (FERC) and potential DER solutions under another (CPUC). Finally, the complications presented by plant retirement and DERs are heightened by the growing number of CCAs.[11] While CCAs present the potential for more effective identification and deployment of local solutions, their growth also highlights the need for area-wide coordination in Local RA procurement to ensure collective procurement sufficiency.

B. Local Sub-Area Market Power

Local market power arises when an ERR holds market power in an LCA or sub-area because there is no other combination of resources that can meet the local reliability need. Competitive procurement is not a near-term option; given the lack of competitive alternatives, only new resources can effectively mitigate market power, and these resources take time to deploy.[12] Even where there is only partial market power, resources can command a higher price than other Local RA resources knowing that they will likely be procured through the CAISO's Capacity Procurement Mechanism at or near the Soft Offer Cap. Consequently, an individual LSE may be reluctant to procure the essential resource because to do so would subsidize other LSEs who meet their shares of the LCR with less costly, non-essential resources. For this reason, and due to a lack of

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[11] The Direct Access ESPs are also LSEs with Local RA requirements, but because their share of system demand has been limited by statute and has remained relatively stable in recent years they have been less of a factor in the recent changes to the Local RA landscape.

[12] And prior to the development of distributed energy resources, physical constraints on building new utility-scale generation or sufficiently large transmission interconnections were often an effective barrier to increasing competition. In addition, the pecuniary impact from market entry that would tend to drive down the price in the local area so that the new entrant may not gain sufficient economic rents to recover its investment.

transparency, these resources may not be procured by LSEs. These factors thus motivate the role of the Central Buyer, as the CAISO has had to step in for the 2018 RA year to procure these essential sub-area resources needed to ensure local reliability.

Not surprisingly, the higher value of these resources due to their position in the market has resulted in them receiving higher prices. The CAISO has paid prices through the Capacity Procurement Mechanism (CPM) and Reliability Must Run (RMR) contracts that are higher than the short-term prices reported by the Commission's Energy Division for other Local RA.[13]

C. CAISO RMR and CPM Procurement

An understanding of the circumstances under which CAISO RMR or CPM[14] backstop has been required will help create reasonable expectations for a multi-year program and central buyer structure.

Two circumstances in which the CAISO engages in backstop procurement through the CPM are particularly relevant in this proceeding. The CAISO procures Local RA resources through this mechanism to address (1) deficiencies in collective LSE Local RA procurement, including deficiencies that may arise due to sub-area constraints despite compliance by all LSEs, and (2) "capacity at risk of retirement within the RA Compliance Year that will be needed for reliability by the end of the calendar year following the current RA Compliance Year."[15] In some cases, these resources may have partial market power as pivotal suppliers or by virtue of their higher effectiveness at meeting granular local reliability needs than other potentially substitutable resources.

[13] CPUC, *The 2016 Resource Adequacy Report*, Energy Division, June 2017.

[14] 2018 was the first year that the CAISO used its CPM authority in the year-ahead timeframe to address a collective deficiency for any IOU service territory.

[15] *Id.* §43A.2.

While these resources may face some degree of competition in their sub-area, in both cases the value of the resource is likely to be relatively high.

As part of the RA process, the CAISO engages in backstop procurement only after issuing a Market Notice identifying the needed resource and providing LSEs the opportunity to procure the resource. If no LSE cures the deficiency, the CAISO procures the needed resources, typically at the Soft Offer Cap (currently $6.31/kW-month).[16,17] If the specific generator whose capacity is needed is unwilling to contract at or below the Soft Offer Cap, the parties may seek authority for an RMR-like COS rate from FERC.[18]

Under the CPM, cost recovery includes the generator's variable costs, net of market revenues, and some amount of capital maintenance expense to ensure cost coverage and some degree of profit. The CPM is based on the going forward costs for an ongoing operation but does not consider recovery of capitalized maintenance costs.

When possible, the CAISO procures Local RA capacity voluntarily through its Competitive Solicitation Procedure (CSP) under its Tariff Section 43.A. A review of CPM transactions for 2009 to 2017, shown in Table CalCCA-1, reveals all but a handful of transactions were priced at the SOC.

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[16] *Id.* §43A.4.1.1.

[17] The initial soft cap was set in 2009 based on the going forward fixed costs for a combustion turbine estimated from siting case submittals in California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies,* CEC-200-2007-011-SF, December 2007. The cap was revised updated for the survey results from 20 combined cycle plants reported in California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies,* CEC-200-2009-07-SF, January 2010. (Dr. McCann was the lead consultant author on both reports.) The soft cap has been revised several times subsequently as described in CPUC, *The 2016 Resource Adequacy Report*, Energy Division, June 2017, p. 32.

[18] CAISO Fifth Replacement Electric Tariff, §43A.4.1.1.1.

Table CCA-1

CAISO CPM Transactions - 2009-2017						
Year	Resource	CPM designation (MW)	CPM designation dates (Mo./Day)	Price $/kW-Mo.	Estimated cost	Local capacity area
2009	Yuba City Energy Center 1	1	4/21 - 5/20	$3.42	$3,417	Sierra
2009	Humbolt Mobile #2 2	15	6/20 - 6/30	$4.28	$21,403	Humbolt
2009	Moutainview #3	2	8/2 - 8/31	$1.95	$3,892	LA Basin
2009	Moutainview #4	2	8/2 - 8/31	$1.95	$3,892	LA Basin
2009	Humbolt Mobile #2	15	8/7 - 9/7	$1.43	$21,403	Humbolt
2009	Balch #3	1.5	8/20 - 9/18	$3.89	$5,837	Fresno
2009	Creed Energy Center #1	48	10/13 - 11/11	$3.89	$186,796	Bay Area
2009	Feather River Energy Center #1	1	10/13 - 11/11	$3.89	$3,892	Sierra
2009	Gilroy Energy Center #3	46	10/13 - 11/11	$3.89	$179,013	Bay Area
2009	Goose Haven Energy Center #1	48	10/13 - 11/11	$3.89	$186,796	Bay Area
2009	King City Energy Center #1	44.6	10/13 - 11/11	$3.89	$173,565	
2009	Lambie Energy Center #1	48	10/13 - 11/11	$3.89	$186,796	Bay Area
2009	Wolfskill Energy Center #1	46	10/13 - 11/11	$3.89	$179,013	Sierra
2010	El Segundo #4 1	20	1/5 - 2/3	$3.89	$77,832	LA Basin
2010	Delta Energy Center 2	127	4/30 - 5/29	$3.89	$494,192	Bay Area
2010	Yuba City Energy Center 3	1	7/18 - 8/16	$3.89	$3,892	Sierra
2010	Huntington Beach #3 and #4 2	182	8/17 -9/22	$3.89	$708,268	LA Basin
2010	Mindalay #1 and #2 4	40	9/27 - 10/26	$3.89	$155,664	BC - Ventura
2010	CalPeak - Enterprise and Border 1	0.7	10/12 - 11/10	$3.89	$2,723	San Diego
2011	Moss Landing Power Block 21	75	9/9 - 9/30	$5.26	$354,988	
2011	Moss Landing Power Block 21	45	10/1 - 10/7			

CAISO CPM Transactions - 2009-2017						
Year	Resource	CPM designation (MW)	CPM designation dates (Mo./Day)	Price $/kW-Mo.	Estimated cost	Local capacity area
2012	Huntington Beach Unit 1	20	2/8 - 3/8	$6.09	$121,810	LA Basin
2012	Huntington Beach Unit 1	98	3/1 - 4/29	$6.41	$1,255,748	LA Basin
2012	Encina Unit 4	300	3/1 - 4/29	$6.41	$3,844,125	San Diego
2012	Huntington Beach Unit 1	226	5/1 - 6/29	$6.40	$2,892,704	LA Basin
2012	Huntington Beach Unit 3	225	5/11 - 10/31	$6.19	$8,360,972	LA Basin
2012	Huntington Beach Unit 4	215	5/11 - 10/31	$6.19	$7,989,373	LA Basin
2012	Huntington Beach Unit 1	226	9/5 - 10/4	$6.40	$1,446,352	LA Basin
2013	Morro Bay Unit 4	50	2/22 - 4/22	$6.41	$640,815	CAISO System
2013	Huntington Beach Unit 2	163	9/1 - 10/30	$6.41	$2,088,642	LA Basin
2014	High Desert Power Project Aggregate	181	2/6 - 3/7	$6.41	$1,159,644	CAISO System
2014	Moss Landing 2	490	10/2 - 12/1	$6.73	$6,593,139	CAISO System
2015	Moss Landing 6	52	6/30 - 7/29	$0.22	$11,661	CAISO System
2015	Oildale 1	40	7/15 - 9/12	$6.73	$538,215	CAISO System
2016	MANDALAY GEN STA. UNIT 2	20.01	11/8 - 1/6	$6.31	$252,526	SCE TAC
2016	MANDALAY GEN STA. UNIT 3	130	11/9 -12/9	$6.31	$820,300	System
2016	Pio Pico Unit 1	102.67	11/9 -12/9	$6.31	$647,848	System
2016	Pio Pico Unit 2	102.67	11/9 -12/9	$6.31	$647,848	System
2016	Pio Pico Unit 3	102.67	11/9 -12/9	$6.31	$647,848	System
2016	Sentinel Unit 1	1	11/9 -12/9	$6.31	$6,310	System
2016	Sentinel Unit 2	1	11/9 -12/9	$6.31	$6,310	System
2016	Sentinel Unit 3	1	11/9 -12/9	$6.31	$6,310	System
2016	Sentinel Unit 6	1	11/9 -12/9	$6.31	$6,310	System
2016	DELTA ENERGY CENTER AGGREGATE	114	12/14 - 2/11	$6.31	$1,438,680	PG&E TAC

CAISO CPM Transactions - 2009-2017						
Year	**Resource**	**CPM designation (MW)**	**CPM designation dates (Mo./Day)**	**Price $/kW-Mo.**	**Estimated cost**	**Local capacity area**
2016	Los Medanos Energy Center AGGREGATE	89.79	12/14 - 2/11	$6.31	$1,133,150	PG&E TAC
2016	MOSS LANDING POWER BLOCK 1	141.04	12/18 - 1/17	$6.31	$1,779,925	System
2016	Mountainview Gen Sta. Unit 3	36.37	12/19 - 2/16	$1.90	$138,206	SCE TAC
2017	MOSS LANDING POWER BLOCK 1	510	Annual	$6.19	$37,882,800	PG&E
2017	ENCINA UNIT 4	272	Annual	$6.31	$20,595,840	SDG&E
2017	ENCINA UNIT 5	273	Annual	$6.31	$20,671,560	SDG&E

Unlike the CPM, RMR contracts have been part of the CAISO grid management tools since the initiation of the restructured market in March 1998. RMR resources are defined as:

> Generation that the ISO determines is required to be on line to meet Applicable Reliability Criteria requirements. This includes: i) Generation constrained on line to meet NERC and WECC reliability criteria for interconnected systems operation; ii) Generation needed to meet Load demand in constrained areas; and iii) Generation needed to be operated to provide voltage or security support of the ISO or a local area.[19]

As described in the Commission's 2016 Resource Adequacy Report, RMR contracts are annual agreements that are reviewed and renewed as needed. RMR contracts typically have been provided to resources for which there are no substitute resources. The contracts typically have a one-year term that can be renewed annually under the same terms and conditions, with compensation set at a price based on the generator's cost-of-service (COS). COS prices are necessary because these resources are local monopoly resources and thus could charge exorbitant rates if procured at "market-based" prices.

In their most recent incarnation, RMR contracts are offered to units that did not bid or accept a voluntary CPM offer, but are still needed for local reliability and stability purposes. Units designated as RMR may receive cost-based remuneration above the CPM SOC with approval of the FERC. However, these prices are not completely comparable "apples to apples" with CPM because CPM recipients retain all wholesale market revenues while for these RMR Condition 2 contracts (which are must-offer bidders), the wholesale revenues are to be returned to the CAISO, hence the "potential" cost

[19] CAISO Fifth Replacement Electric Tariff, March 16, 2018, Appendix A Master Definition Supplement.

description. Table CalCCA-2 lists the most recent additions to the RMR designations for 2018, and the contracted price in $/kW-month.

Table CalCCA-2

RMR Unit Designation for 2018	NQC MW (Aug.)	Potential Cost ($/kW-Month)
Metcalf	**580**	**$10.41**
Yuba City	**47.6**	**$7.81**
Feather River	**47.6**	**$7.76**

The higher value of these critical resources is also confirmed by the prices paid by the IOUs for utility-owned generation (UOG) providing Local RA in their service territories. Southern California Edison (SCE) paid $435,219,778 in 2017 for 2,534.3 MW of CAM reliability capacity at an average price of $14.31/kW-month according to SCE's 2017 FERC Form 1 filing. Pacific Gas and Electric Company's (PG&E's) FERC Form 1 reveals a cost of $203,474,897 for 1,637.3 MW of CAM resources, at an average price of $10.36/kW-month. For PG&E's PCIA-eligible fossil RA generation PPAs, the total cost was $478,244,526 for 2,486.4 MW at an average cost of $16.03/kW-month.

The key lesson from these observations is that expecting resources with partial or complete market power to negotiate "competitive" rates that resemble the short-term price for Local RA is unrealistic. These resources, as rational market actors, will logically seek to recover as much as they can from buyers, whether the CAISO, IOUs, other LSEs or a new Central Buyer. Until local sub-area constraints are eliminated, these resources can demand higher prices and their market power is only limited by the CAISO authority to require acceptance of an RMR contract that is tied to their cost of service. Only the imposition of a FERC-authorized mechanism can limit those prices to either a defined cost basis under a voluntary transaction or an approved cost of service basis for must-offer resources. A Central Buyer will need this same authority to compel generator participation. Nevertheless, a Central Buyer is only needed to procure from these pivotal suppliers for the period when those resources can exert market power. With the successful implementation of the Long-Term Strategy, that role should diminish as local sub-are constraints continue to be removed.[20] Once market power is addressed, LCRs can be defined at sufficient granularity to align with the CAISO's actual grid needs,[21]

CalCCA does not dismiss the possibility of achieving prices below the Soft Offer Cap for these resources with more transparent information and an expanded procurement timeline. In the near term, the most viable way of achieving lower prices– as the Commission has fully recognized – is to offer the generator multi-year contracts.

III. CALCCA'S PROPOSED TRANSITION PROGRAM

The economic interests of all LSEs are naturally aligned to ensure local area reliability while reducing overprocurement of Local RA and ratepayer costs. Pending physical solutions to address underlying local area constraints, and consistent with the Commission's directives, CalCCA's Transition Program will achieve these objectives through (1) a three-year compliance obligation, (2) greater transparency in local sub-areas, and (3) a centrally-procured residual Local RA amount in each local capacity area (LCA). Added transparency into local area and sub-area requirements will also

[20] For example, when the restructured market was initiated in March 1998, the vast majority of power plants in the Los Angeles Basin had at least one unit on a RMR agreement. Today, almost all of those plants have been removed from the RMR designation contracts and a few show up on the CPM procurement list.

[21] In the development of the LCR framework, the Commission chose to aggregate six of the local capacity areas in PG&E's TAC area, to mitigate local market power concerns (See Energy Division Proposal, p. 12.)

incentivize and maximize opportunities for LSEs, separately or collectively, to procure effective Local RA capacity and reduce the need for central buying.

Recognizing that some degree of central buying may be necessary in the near term – particularly for resources with market power – CalCCA proposes to rely on the CAISO as the Central Buyer for the residual Local RA needs, using existing mechanisms modified as described below to meet current needs. The CAISO appears to be the ideal entity, with the tools and legal authority to spread costs across both IOU and POU service territories based on cost-of-service rates (if and when negotiation with the essential resources fail) until local constraints can be relieved. The CAISO is also well positioned to compensate LSEs who step forward to procure sub-area resources to the benefit of all LSEs with modifications to the existing CPM cost allocation.

A. Transition Program Mechanics

CalCCA has identified six key steps in a rolling, annual, three-year-forward RA program. The six steps would occur over a 15-month period leading up to the start of each three-year RA compliance cycle. In conjunction with the proposed six-step structure, CalCCA recommends the RA compliance year be re-defined on an April 1 to March 31 basis rather than the calendar year, as discussed further below. Thus, the timeline for the six steps would occur from January 1, 2019 through March 31, 2020 for the April 2020-March 2023 RA cycle.

The six steps, with illustrative timings for each of them, are as follows:

Step 1: CAISO performs LCR studies to determine Total LCR values for each year of the upcoming three-year RA cycle and for each LCA, and identifies Essential Reliability Resources (ERR), if any (January 1 – May 31, 2019)

Step 2: Utilities provide CAM forecasts to the CPUC for each year of the upcoming RA cycle (by May 31, 2019)

Step 3: CPUC calculates annual Net LCR = (Total LCR – POU share – CPUC Jurisdictional LSE share of ERR– CAM) for each LCA and allocates shares to LSEs (by June 30, 2019)

Step 4: LSEs procure required percentages of their shares of Net LCR for each of the three years, as specified in the table below (July 1 – September 30, 2019), a process that must be coordinated with any IOU sales of RA to other market participants.

Step 5: LSE provide showings of their System, Flexible and Local RA procurement for April 2020 through March 2023 to CPUC and CAISO (by October 1, 2019)

Step 6: For each LCA CAISO calculates Residual needs, including needs driven by sub-LCA constraints. The Central Buyer then procures the Residual Need and any ERR capacity not already procured by LSEs (by December 1, 2019 – four months ahead of the start of the next RA compliance year).

Each step is discussed in detail below, and Appendix A provides a process overview and timeline.

CalCCA's six-step Transition Program does not depend on the proposed change in the compliance-year time period from January 1 through December 31 to April 1 through March 31, and could be implemented without the change. A change in the compliance period may be desirable, however, as certain existing processes would need to be moved forward to preserve the four-month lead time between Step 6 and the beginning of the compliance period.[22] First, the change allows for greater certainty in the results of the CAISO multi-year forecasts (Step 1). The CEC's Integrated Energy

[22] CalCCA proposes this four-month period based on the understanding that generating resources that may need to be procured by the Central Buyer need this much advance notice of procurement.

Policy Report (IEPR) demand forecast is critical to the CAISO's study process. The CEC typically adopts the forecast in January, suggesting that the CAISO cannot begin the study process before February 1. Second, the change in timeline will allow the LSEs and Central Buyer to complete all procurement, including contracts with ERRs that have local market power, at least four months prior to the start of the compliance period (Step 6). This schedule gives more certainty to generators which CalCCA expects will lead to better maintenance planning, increased reliability and lower costs for ratepayers.

STEP 1: CAISO Performs LCR Studies and Identifies Essential Reliability Resources

The Commission observed in the Scoping Memo[23] and D.18-06-30[24] that greater transparency of resource requirements in local areas and sub-areas may be one means of reducing out-of-market Local RA procurement. Step 1 of CalCCA's Transition Program thus starts with the CAISO LCR study process and concludes by May 31, when the CAISO provides the LCR and identifies ERRs for each local area and each year of the multi-year compliance period. In addition to ERRs, the CAISO LCR report identifies available resources within an LCA and indicates their different effectiveness on critical sub-area constraints. While this information will be useful to the CAISO as Central Buyer, it will also be useful to LSEs as they conduct their Local RA procurement and attempt to reduce the need for central buying. Lastly, the CAISO will identify what share of the LCR in each LCA will be met by POU procurement.

[23] Scoping Memo at 4.
[24] D.18-06-030 at 44.

STEP 2: Utilities Provide Multi-Year CAM Forecasts

The allocation of Local RA capacity by the IOUs requires a clear understanding of anticipated allocation of Local RA capacity by the IOUs under the Cost Allocation Mechanism (CAM). Today, CAM allocations are provided by the CPUC in late July and then trued up on a quarter-ahead basis during the compliance period. To support a multi-year program, the IOUs must provide to the Commission their then-current three-year forecasts of CAM resources for each LCA at the same time the CAISO provides its LCR study results at the end of Step 1. The CPUC will use the CAM forecasts in Step 3 to determine Net LCR amounts and allocate them to LSEs.[25] LSE specific CAM allocations for Year 2 and Year 3 would be revised annually based on updated information and the Year 1 allocations would be revised quarterly as is done today.

In addition to CAM Local RA resources, the IOUs currently hold Local RA resources in their Power Charge Indifference Adjustment (PCIA) eligible portfolios. While future disposition of these resources is under consideration in R.17-06-026,[26] the CPUC must at a minimum receive this information from the IOUs by LCA and year and include it in calculating the Net LCR allocations in Step 3.

STEP 3: CPUC Allocation of Net LCR Requirements to LSEs

Using the information from Steps 1 and 2 above and the CPUC Jurisdictional LSE share of the Total LCRs, the Commission calculates Net LCR for each LCA and

[25] For the CPUC to allocate the Net LCRs for the three-year period to LSEs, it will need a three-year forecast from each LSE; CalCCA recommends that the current annual load forecast that is submitted in April be a three-year load forecast

[26] Proposals for disposition of this Local RA capacity include long-term resource or product sales (CalCCA) and quarterly allocation of Local RA attributes associated with hydro resources among LSEs (Joint Utilities) and periodic sales of Local RA attributes from other IOU resources (Joint Utilities).

compliance year. The Net LCR is calculated as (CPUC Jurisdictional LSE Share of Total LCR – CPUC Share of ERR - CAM). The Commission then allocates shares of Net LCR among jurisdictional LSEs. The CalCCA timetable calls for the Commission's provision of Net LCR allocations to LSEs by July 1.

STEP 4: LSE Procurement of Net LCR

Once the Commission has provided the Net LCR allocations, the LSEs have three months (July – September) to secure 90 percent of their Net LCR shares for Years 1 and 2, and 80 percent for Year 3. LSEs would also have opportunities to procure prior to the July 1 allocation but would have less information to rely upon before further Local RA procurement. Setting LSE procurement requirements below 100 percent of the Net LCR still results in procuring the required 100 percent of Net LCR for Year 1 and 95 percent for Year 2 when combined with the Central Buyer procurement.[27] At the same time, these LSE procurement levels provide headroom that the Central Buyer can use to address remaining sub-area needs with reduced risk of over-procurement by the end of Step 6. Table CCA-3 below shows CalCCA's proposal for the LSE and Central Buyer procurement shares of the Net LCR for each compliance year, and illustrating the rolling three-year RA compliance cycle.

[27] The Central Buyer will not procure an ERR for Year 2/3 unless it is still not procured when it is needed for Year 1; this is necessary to avoid undermining ERR incentives to sign multi-year contracts with LSEs

Table CCA-3: Procurement of Net LCR by LSEs and Central Buyer

	2020-1	2021-2	2022-3	2023-4	2024-5
2020-22 RA Cycle	**Year 1**	**Year 2**	**Year 3**		
Net LCR achieved	100%	95%	80%		
LSE procurement requirement	90%	90%	80%		
Central Buyer procurement	10%	5%	0		
2021-23 RA Cycle		**Year 1**	**Year 2**	**Year 3**	
	Net LCR	100%	95%	80%	
	LSEs procure	90% (done already)	90% (10% more)	80%	
	Central Buyer	10% (5% more)	5%	0	
2022-24 RA Cycle			**Year 1**	**Year 2**	**Year 3**
		Net LCR	100%	95%	80%
		LSEs procure	90% (done already)	90% (10% more)	80%
		Central Buyer	10% (5% more)	5%	0

The LSE procurement efforts should focus not only on Local RA generally, but on ERRs and other resources that are most effective in addressing sub-area constraints.

An LSE's obligation may be met by new non-fossil resources. These resources can be counted for Year 1 under existing guidance. Under the Transition Program, for Years 2 and 3, these resources can be counted towards an LSEs requirement under three conditions: (1) the LSE has executed a contract for purchase or development; (2) the project is already in the utility's or the CAISO's interconnection queue and (3) the scheduled commercial operation date falls on or before the first date of the compliance month in which the LSE wishes to count the resources towards its obligation.

One additional factor must be considered. Several parties contemplated in R.17-06-026 that the IOUs will sell some portion of their existing RA resources or, at a minimum, RA products. It is critical that any IOU sales with Local RA value be timed in a way that optimizes the potential for use by other LSEs and maximizes revenues for ratepayers.

STEP 5: LRA Compliance Showing

LSEs would make their annual three-year showings on October 1. For Year 1, this would also include the annual System and Flexible RA Showing. To the extent an LSE falls short of its required Net LCR procurement share, that shortfall will be included in the Central Buyer procurement in Step 6 with a corresponding adjustment to the LSE's share of the Central Buyer's procurement costs. This is consistent with how the CAISO handles individual LSE deficiencies in local capacity procurement today.

To the extent an LSE has met its Net LCR compliance target and has procured excess Local RA in an LCA, no compensation would be provided to the LSE (e.g., in the form of a reduced share of the Central Buyer procurement costs). This is consistent with the practice today when an LSE showing includes Local RA in excess of its obligation but the CAISO determines there is a collective deficiency. The reasoning is that self-provision of Local RA beyond the Net LCR target does not necessarily offset needs for the Central Buyer to procure highly-effective local resources on sub-LCA constraints. In contrast, to the extent an LSE has procured ERRs, the procurement would offset its share of the ERR costs 1:1 up to its proportional share of those costs because it would directly offset the need for Central Buyer procurement. Further, the CAISO could also credit the LSE for any excess ERRs procured beyond the LSE's load-ratio share at the CPM Soft

Offer Cap.[28] The credited costs will be recovered by the CAISO from all other LSEs, including IOUs, POUs, CCAs and ESPs, in proportion to their unmet shares of these critical resources. This outcome fairly allocates these costs to all entities that benefit and incentivizes LSEs to procure from ERRs if they can obtain a price better than the CPM Soft Offer Cap.

STEP 6: CAISO Calculation of Residual Need and Central Buying

Based on the October 1 LSE showings, the CAISO will assess residual or unmet Local RA needs for each LCA and each year of the three-year RA cycle, including any needs driven by sub-LCA constraints. The Residual Need will equal (Net LCR — CPUC Jurisdictional LSE showings). Under CalCCA's proposal that LSEs procure 90 percent of their shares of Net LCR for Year 1, and assuming all LSEs meet that target, the Residual for Year 1 will equal (10%*Net LCR),and may include other specific resources needed to address sub-LCA constraints. The CAISO as Central Buyer will then procure some or all of the remaining Net LCR amounts, as specified in Table 1 above, plus the ERR capacity identified in Step 1 that has not been procured by an LSE for Year 1. Thus, for Year 1, the process obtains at least 100 percent of the Net LCR by summing the procurement of the Net LCR as specified in the table (e.g., for compliance year 1 90% met by LSE and 10% met by Central Buyer), and if necessary any additional resource procurement by the

[28] The LSE procuring excess ERR or sub-area resources would not be exempt from the costs actually incurred for the net procurement of the Central Buyer. Today, the CAISO tariff section 43.2.2.1 provides a "proportional credit," meaning the procuring LSE is subsidizing other LSEs by paying for the RA while all LSEs will benefit by proportionally reduced CPM costs. This is a weakness in the current structure that we address in our transition proposal by offering a 1:1 credit instead of a proportionate credit (and limited to the ERRs) to create the proper incentives. Section 43.2.2.1 provides: "Any Scheduling Coordinator that provides such additional Local Capacity Area Resources consistent with the Market Notice under this Section shall have its share of any CPM procurement costs under Section 43.8.3 reduced on a proportionate basis."

Central Buyer to resolve sub-LCA constraints. When combined with POU procurement, ERR procurement and CAM resources, at least 100% of the Total LCR is achieved.

Because the CAISO will have detailed knowledge of any sub-area needs and the different effectiveness values of different resources, the Central Buyer step should result in more efficient procurement of the Local Capacity than if LSEs were to procure 100% of their Net LCRs as is done today. This should reduce the risk of overprocurement and the likelihood of need for further CAISO backstop procurement for collective deficiency. Costs of Central Buyer procurement would be allocated equitably among all responsible LSEs,[29] including IOUs, POUs, CCAs and ESPs.

B. Effectiveness of CalCCA's Proposed Transition Program

CalCCA's proposed Transition Program effectively addresses many of the key goals identified in Section I above. The program:

- ✓ Abates collective overprocurement of Local RA and mitigates unnecessary ratepayer costs by (i) providing early identification of ERR and other highly-effective local resources, (ii) providing an opportunity for an LSE or group of LSEs to procure the resources at a price lower than CAISO CPM Soft Offer Cap, and (iii) providing an opportunity for the CAISO to act as a Central Buyer to secure the residual remaining local resources that it deems necessary for reliability as informed by individual LSE's procurement;

- ✓ Ensures LSEs can act on their preferences for local resources, by providing transparency on what resources are needed, with time to procure those resources, while also narrowly defining the role of Central Buyer.

- ✓ Allocates costs equitably across LSEs by avoiding cross-subsidies between POUs and Commission-jurisdictional LSEs while also compensating individual LSEs for procurement that benefits all LSEs;

[29] RMR costs are recovered through the transmission charges collected from utility distribution companies (UDCs), including POUs, served by the CAISO transmission grid. The UDCs then recover these costs from ratepayers through their retail transmission charges. CPM costs due to the collective deficiency are allocated *pro rata* on a load-share basis to each LSE serving load in the TAC area in which the deficient LCA was located. The LSEs then recover these costs from ratepayers through their retail generation rates.

- ✓ Mitigates the impacts of planned and unplanned resource retirements and reduces market uncertainty by encouraging LSEs to procure multi-year RA contracts;

- ✓ Aligns scale between buyers and sellers, by leaving an opportunity for group procurement of larger resources and providing credit for LSEs that procure ERR beyond their own needs; and

- ✓ Reduces CAISO backstop procurement through transparency of sub-area information, greater opportunity for LSEs to act on that information and alignment of LSE economic interests to reduce overprocurement and ratepayer costs.

Pending progress through the Long-Term Strategy, LSEs can individually focus on decarbonization and DAC solutions in their local communities.

C. Other Related Issues

The success of the Transition Program hinges not only on Commission action, but on coordination of existing processes in progress at the Commission, CAISO and CEC and changes to CAISO tariffs. For example, the CAISO's Flexible Resource Adequacy Criteria Must Offer Obligation process (FRACMOO-2), will include a must offer obligation for RMR so that flexible and system capacity attributes of RMR resources are not lost. Specific reforms to the CPM and RMR processes also will be required, including (1) adopting a definition of "Essential Reliability Resource," (2) establishing a process for a three-year ERR forecast, which will need to be coordinated with these solutions, (3) coordinating central buying with the Commission's multi-year program and (4) facilitating payment to LSEs who purchase certain resources to the benefit of all LSEs. In addition, coordination of Local RA and Flexible RA programs must be ensured. All of these activities will drive the success of the Transition Program and should be considered in another phase of this proceeding, in coordination with the CAISO.

In addition, any central buying program, including the Transition Program, should be reviewed on a regular basis to ensure it is achieving the desired goals. CalCCA recommends that the first review take place 18 months after the commencement of the central buying program, with annual updates thereafter.

IV. LONG-TERM LOCAL RA STRATEGY

The Track I Decision, following the Scoping Memo, appropriately focused on reducing out-of-market procurement, using a multi-year Local RA program and increased transparency to LRA needs. While this objective is important in the near term, solutions should not end with improvements in the way Local RA is procured under local area constraints. As long as these constraints exist, they will confer market power on certain generators, preventing "competitive" procurement, and support continued reliance on fossil fuel generation. The Commission and stakeholders must complement their efforts to develop a multi-year program with a structured process toward the ultimate objective: reducing or eliminating the local area constraints that cause out-of-market procurement in ways that promote decarbonization and benefit DACs. CalCCA's Long-Term Strategy offers a practical approach to begin this discussion, relying on existing regulatory mechanisms.

Distributed energy resources (DER) hold particular promise in relieving constraints and thus play a central, although not exclusive, role in the Long-Term Strategy. LCAs are typically densely populated areas, and most are currently experiencing high rates of DER adoption, which over time changes the shape and size of local-area demand and local-reliability needs. The latest indication of the potential for DER is in the 2017-18 comprehensive transmission plan, which identifies $2.6 billion savings from eliminating or downsizing previously-approved transmission upgrades. These reductions were for reliability upgrades to support constrained areas of the grid. The Oakland Clean Energy Initiative, recently approved in the 2017-18 comprehensive transmission plan, offers an example of the successful elimination of a fossil generating plant that was needed for local reliability by a combination of grid assets and preferred DERs. CalCCA's proposed Long-Term Strategy builds on state policies and trends by advancing the growth of preferred resources, including DER, as a solution for local area constraints.

The Long-Term Strategy focuses on two necessary areas of activity, which together can accelerate elimination of market power in LCAs and replacement of fossil-fuel generation with DER. At a policy level, the Commission must resolve open questions that currently present barriers to deploying DERs. If these questions are resolved, then cost-effective DER-based solutions can reasonably be evaluated and adopted through the CAISO transmission planning process as non-wires alternatives (NWA).

Movement toward the ultimate goal will take time, requiring reliance in the interim on a multi-year program like CalCCA's Transition Program. Recognizing the demands of time, CalCCA recommends adopting a process and general goals in its decision in this Track to initiate longer-term strategies. CalCCA proposes adoption of its Long-Term Strategy to provide such a framework.

A. Removing Existing DER Barriers

Two challenging areas must be addressed to facilitate the desired long-term transition of California's grid reliability needs through DER deployment. One is the matter of resource valuation and appropriate cost recovery, which requires regulatory resolution by the Commission; the other has to do with operation of DERs as grid assets, which will involve coordination between the CAISO and the relevant distribution utility to support DER provision of transmission services.

DER deployed to offset local grid constraints have unique value that can be compensated in different ways. In concept, if the DER deployment is fully intended for offsetting the need for further transmission build-out, then such DER deployment could be treated as a cost-based ATS (i.e., a transmission asset), thereby having its costs recovered through transmission rates. One complication with the ATS path, however, is that transmission assets become part of the CAISO controlled grid and as such are subject to CAISO operational control. But to integrate DER as transmission assets will require rules and procedures for coordination between the CAISO, the distribution utility and the DER operator to ensure that the DER is able to deliver the needed transmission services over the distribution system. To date such coordination procedures have not yet been developed; developing such procedures will require collaboration between the CAISO, the distribution utilities, and DER providers, with Commission review of any implementation needs of the IOUs. Another complication to the ATS path for DER is the need to establish methodology under the locational net benefits analysis (LNBA) element of the DRP framework to quantify the transmission benefits of DERs. Policy resolution by the Commission is important to ensure that DERs are fully compensated for the value they provide.

Alternatively, the same DER may also help defer the need for distribution grid build-out, therefore it may be appropriate to recover some of the build-out costs through distribution rates. In this scenario the same DER would be engaged in "multi-use applications" (MUA), *i.e.,* providing services to and receiving compensation from two different entities: the CAISO with regard to the provision of transmission services, and the distribution utility with regard to provision of distribution services.[30] This is an attractive scenario because the ability to "stack" services and revenue sources would increase the financial viability of the DER. However, it raises other unresolved MUA issues, including priorities among service obligations when needs of the CAISO and distribution utility may be in conflict, and measurement of the resource's performance so as to ensure that both the CAISO and the distribution utility compensate the resource accurately for services received.

There are other cost allocation issues related to MUA that must also be addressed. For example, if a storage resource procured by an IOU serves both generation needs and distribution system functions, there is the potential for costs of generation services that benefit the IOU's bundled customers to be characterized as distribution costs and thereby shifted to other LSEs' customers. The specific matter of appropriate cost recovery for energy storage MUA is currently under consideration in consolidated A.17-12-002 and A.17-12-003 but may also require consideration for other resources.

The CAISO is presently exploring one type of MUA through its "Storage as a Transmission Asset" stakeholder initiative. The scenario being considered is one where the storage asset provides transmission services to the CAISO for part of its cost recovery and participates in the CAISO market for the rest. This is an important first step toward operationalizing MUA by allowing dual cost recovery mechanisms for the same facility,

[30] For details on rules adopted to date and open issues regarding MUA of storage resources see the Commission's January 17, 2018 decision in Track 2 of the Energy Storage Proceeding, R15-03-011, in particular section 4.2 on open issues assigned to continuing working groups.

one through transmission rates and another through market revenues. But the scope is limited to transmission-connected resources at this time, out of necessity to set aside the matter of operational coordination with the distribution utility that a DER would require. Consequently, there is still a need to develop a coordination framework to enable CAISO operational control of a DER-based ATS.

Up to now, DER deployment has been compensated primarily through services the DER provides to end-use customers (*i.e.,* typically installed behind the meter) and to LSEs as energy and RA capacity resources, rather than as grid assets obtaining cost recovery through distribution or transmission rates. Thus, for the next few years the NWA path, which treats the DER solutions as resources rather than grid assets, will be the most accessible path for DER to address local reliability needs without building new transmission. The challenge here, though, is that even though DER in this scenario offset the need for a transmission upgrade, they do not receive any compensation reflective of the avoided cost of that upgrade and must rely entirely on contracts with LSEs and revenues from the CAISO spot markets. An important open policy question is whether and how DERs targeted to offset transmission upgrades for local reliability can receive the avoided-cost value they provide, without shifting costs between bundled customers and the customers of other LSEs.

As the Commission and various stakeholders consider and work through the DER-related challenges of valuation, compensation, and operations, the Commission could explore the merits of establishing incentives to further state policies through preferred resource solutions to local reliability needs. One possibility could be for the Commission to explore the merits of using Greenhouse Gas (GHG) allowance revenues or other revenue sources as funding pathways for incentives to prioritize the build-out of local preferred resources alternatives within DACs. Another opportunity could be the potential for the CPUC and the CEC to coordinate and partner to structure incentives and pilots of new DER technologies and control systems that would further reduce Local RA needs.

The valuation and compensation questions surrounding DER, which the Commission began to tackle in the IDER and DER proceedings, are complex and have yet to be solved. CalCCA recommends that the Commission rededicate its efforts toward a multi-agency approach, including the CAISO and CEC in a process aimed to resolve the issue over the next year to support preferred resource solutions by late 2019.

B. Implementing DER Solutions to Transmission Constraints

The CAISO Transmission Planning Process (TPP) identifies transmission upgrades that most cost effectively eliminate or substantially reduce LCA constraints, including sub-area constraints. The Commission and the CEC inform the TPP by providing a range of information, including scheduled power plant retirements, the IEPR demand forecast and forecasts of load modifiers (energy efficiency, electric vehicle and rooftop solar adoption), necessary to support the development of an accurate transmission plan. For the current 2018-19 planning cycle the CAISO has already committed to perform such studies for some of the LCAs, with a particular focus on eliminating fossil-fuel generation and improving air quality in disadvantaged communities, and will provide the results in fourth quarter this year. A coordinated initiative between the Commission and the CAISO, addressing three key areas, could further enhance the TPP and enable increased integration of DER solutions.

First, unless there is a driving reliability need for transmission upgrades, a transmission upgrade to relieve LCA needs must be evaluated as an economic project. This requires that the proposed transmission solution must provide net economic benefits compared to the status quo. The CAISO evaluates economic transmission alternatives using its Transmission Economic Assessment Methodology (TEAM). This methodology considers a range of benefits in evaluating transmission alternatives, including economically driven transmission evaluation criteria and other benefits (*e.g.,* limited "public policy benefit"). Further coordination with the CAISO to ensure the methodology fully considers the benefits and values represented by state policy goals would improve the success of DER solutions.

Second, the TPP today does not provide sufficiently detailed information to allow LSEs and developers to evaluate and propose suitable solutions. CalCCA's Long-Term Strategy contemplates that the CAISO would specify performance requirements that an NWA or ATS must meet to avoid the transmission upgrade. Once the CAISO provides this information in the course of its TPP, parties could propose an NWA or ATS to meet the same need with local preferred resources. CalCCA proposes initially targeting areas where central buying is required (due to market power concerns) and where local reliability requires fossil-fuel resources that may not yet be scheduled to retire, with the aim of ultimately removing the need for this procurement. LSEs could propose, perhaps in partnership with DER developers or distribution grid operators, effective solutions that help to enhance the affordability of clean energy resources in DACs.[31]

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[31] The 2016 EPIC grants for "Advanced Energy Communities" administered by the CEC offer examples of innovative clean energy and resilience project funding targeted to DACs and other communities. This program did not, however, specifically target reduction of Local RA

Third, timing considerations warrant exploration. A goal should be to ensure that CAISO solicitations in the TPP process for NWAs and ATS are well timed and designed to solicit preferred resource DER project solutions. Consideration must be given the timing and interplay of the TPP and the IRP to maximize the development of alternatives and accelerate implementation. Furthermore, any refinements to Commission-based policies regarding DER valuation and compensation, discussed above, must be reached expeditiously and implemented in sync with the TPP and IRP processes.

C. Long-Term Strategy Benefits

The Long-Term Strategy may be perceived as a formalized, natural extension of current trends and the existing relationship between the Commission, CAISO and other stakeholders. Looking closer, however, it changes the local reliability landscape in two key ways, (1) more directly targeting preferred resource development to address local reliability needs and (2) providing all stakeholders with the same information on reliability requirements in a transparent and coordinated manner.

Currently the adoption of DER has not been targeted to offset local capacity or transmission needs; the $2.6 billion in reduced transmission needs has been a positive but unintentional side effect of rapid DER growth through customer adoption. In contrast, the Long-Term Strategy would build on presently unstructured DER adoption by explicitly targeting preferred resource development, including additional DER adoption, to offset LCRs. Importantly, however, the Long-Term Strategy would enable all LSEs (or groups of LSEs) – not only IOUs -- to participate in developing solutions.

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needs, which ought to be a consideration in designing future community-focused grant programs. For a summary of the awards see: https://www.lgc.org/epic-approach-advanced-energy-communities/

The Commission's Resolution E-4909 issued earlier this year is a useful example of targeted procurement of preferred resources to meet local reliability needs. The Resolution authorized PG&E "to hold competitive solicitations for energy storage and/or preferred resources, to meet specific local area needs in three specified subareas."[32] Resolution E-4909's implicit rationale for directing PG&E to procure the desired local resources to the exclusion of other LSEs was apparently one of urgency: "Resources procured pursuant to this solicitation must be on-line and operational by a date sufficient to ensure that the RMR contracts for the three plants – Metcalf Energy Center, Feather River Energy Center, and Yuba City Energy Center – will not be renewed for 2019."[33]

In fact, however, none of the resources procured by PG&E will be in service on time to meet this requirement of the Resolution. Of the total 567.5 MW of energy storage PG&E proposes to procure, only 10 MW come on-line in October 2019 and the rest only in December 2020,[34] so there will be no impact on local reliability needs until the 2021 RA compliance year. Directing the utility to undertake the desired procurement is unnecessary and unfairly imposes costs on other LSEs and their customers over which they have no input or control. Instead, the Commission should focus its efforts on facilitating a broader opportunity for all LSEs and other stakeholders to procure local preferred resources to offset grid reliability constraints that drive a continued reliance on an aging and polluting fossil-fuel generation fleet. This principle is at the heart of CalCCA's Long-Term Strategy proposal.

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32 Resolution E-4909 at 1.

33 *Id.* at 9.

34 PG&E Advice Letter 5322-E page 1.

D. Long-Term Strategy Implementation

The current 2018-19 CAISO transmission planning cycle provides an opportunity to launch the Long-Term Strategy. In April, the CAISO announced a transmission study plan for the current 2018-19 planning cycle aimed at eliminating or reducing as far as possible LCRs in a selected set of LCAs, chosen with the objective of eliminating reliance on local fossil-fuel resources.[35] The CAISO has indicated its intent to identify, by fourth quarter of this year, the economic transmission projects that would be most cost-effective in eliminating the Local RA needs. For those LCAs where the transmission solution would provide net economic benefits, the CAISO would include these projects in its 2018-19 comprehensive plan for Board approval. The current CAISO approach does not, however, explicitly allow an opportunity for parties to propose an NWA or ATS to meet the same needs, other than through the relatively brief stakeholder comment period following the fourth quarter stakeholder meeting.

The CalCCA proposal would extend the window for submission of NWA or ATS by stakeholders to the fourth quarter of the next TPP cycle – to the end of 2019 in this first year iteration. This extension is particularly important for LCAs where existing fossil-fuel resources are not yet scheduled to retire, and the CAISO's identified transmission upgrade may not meet the economic benefit-cost requirements for approval. Allowing sufficient time to develop cost-effective preferred-resource alternatives could be the pivotal factor in eliminating the need for the local fossil resource.

The Long-Term Strategy anticipates the CAISO's completion of its current assessment of the selected LCAs this year. Over the following two annual transmission

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[35] See the CAISO's stakeholder presentation at: http://www.caiso.com/Documents/Presentation-LocalCapacityRequirementReductionStudy.pdf

planning cycles the CAISO would similarly study all LCAs in the system. Design of NWA/ATS proposals by stakeholders could begin by the end of 2018 for the LCAs the CAISO studies this year, with the DER-based NWA/ATS potentially implemented within the two to three years following CAISO assessment and selection of the preferred alternatives in the 2019-20 TPP cycle. Thus, the LSEs would use the results of the CAISO planning studies to participate in developing NWA/ATS to address local reliability needs, and would include such projects in their IRPs. Any such development of NWA or ATS would also be included in the LSE's IRPs. At the Commission level the combination of all LSE IRPs would then reflect the Long-Term Strategy to implement local preferred resources to ensure local area reliability while phasing out fossil-fuel resources that have been needed for this purpose, rather than assuming indefinite continued reliance on the non-OTC fossil resources to support local reliability.

V. CONCLUSION

Near-term implementation of CalCCA's multi-year Transition Program promises to change the way in which Local RA is procured, with the aim of reducing out-of-market procurement and overprocurement thereby reducing Local RA procurement costs overall. This approach not only will achieve these initial goals, but will avoid the need for material structural changes by capitalizing on existing procurement mechanisms and institutions. The evolution of Local RA procurement should not stop, however, with improvements in the way Local RA is procured in the short term. As long as local constraints exist, they will confer market power on certain generators who will be able to demand sufficient payment to run indefinitely. Expecting resources with partial or complete market power to negotiate "competitive" rates that resemble the short-term price for Local RA is unrealistic. The Commission must thus complement the Transition Program with a structured step toward the ultimate objective: reducing or eliminating the local area constraints that cause out-of-market procurement through deployment of resources that promote decarbonization and benefit DACs. CalCCA's Long-Term Strategy offers a framework to begin this journey. For these reasons, CalCCA recommends the adoption of the Transition Program and the Long-Term Strategy.

APPENDIX A

Local Reliability

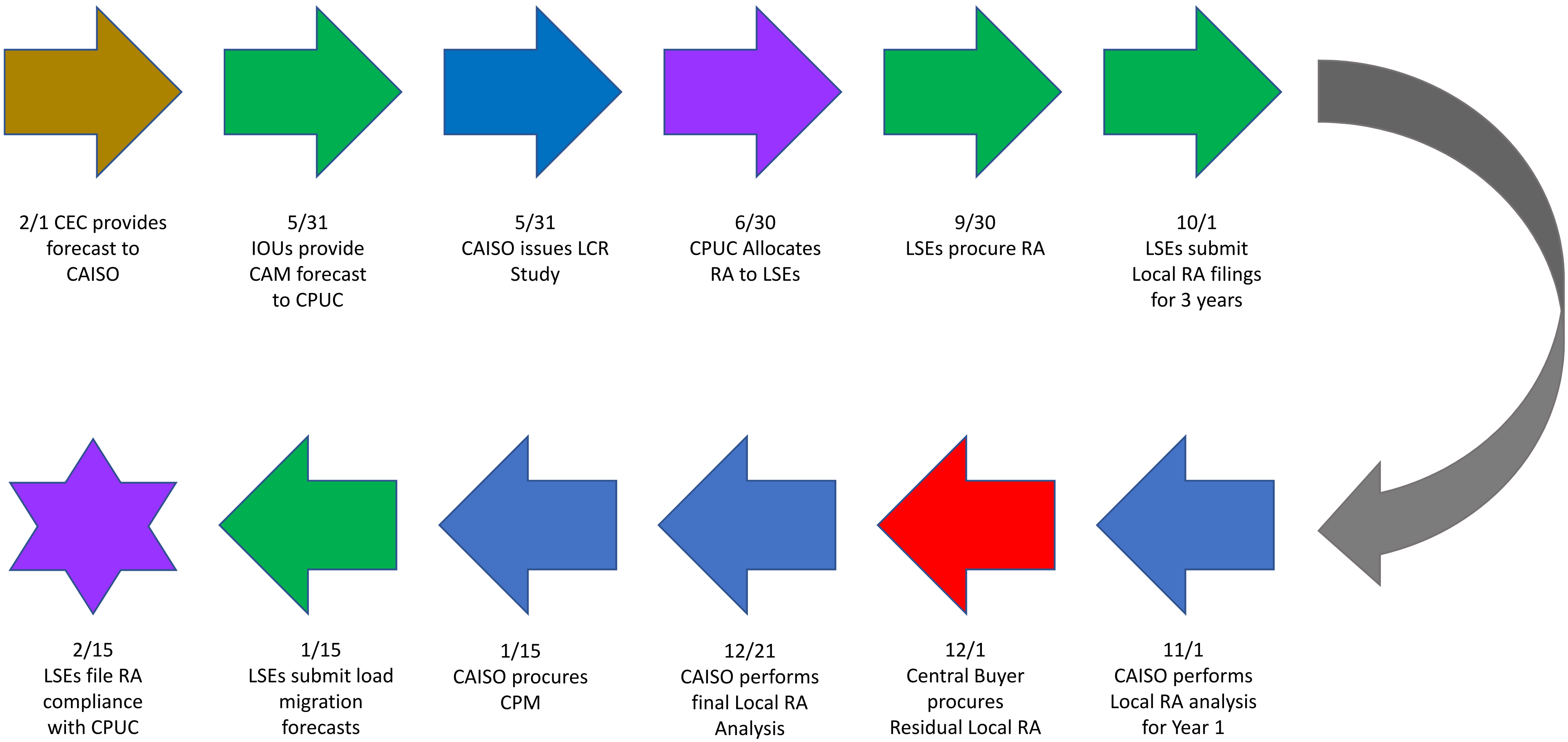
Transition Program

Process Overview and Timeline

Local RA Procurement Process – April 1 Compliance Year

Step	Due Date	CPUC	CAISO	CEC	CPUC LSEs	Munis	Central Buyer	Activity
0	1-Feb		●	●				**CEC** provides to **CAISO** peak demand forecasts used for System and Local RA.
1	31-May	●			●			**IOUs** provide CAM forecasts for each year of the upcoming RA cycle to **CPUC**
2	31-May	●	●					**CAISO** completes 3-year forward Local and Flexible Capacity Study and provides the list of ERR resources (years 1 through 3) to **CPUC**.
3	30-Jun	●	●		●	●		**CPUC** allocates net local RA requirements (years 1 through 3) to **CPUC-Jurisdictional LSEs**, and **CAISO** allocates net local RA requirements (years 1 through 3) to **Munis**
4	30-Sep				●			**CPUC-Jurisdictional LSEs** procure required percentages of their shares of Net LCR for each of the three years.
5	1-Oct	●	●		●	●		**CPUC-Jurisdictional LSEs** and **Munis** submit RA filings to **CPUC** and/or **CAISO**, demonstrating 90% of net LRA requirements for year 1, 90% of net LRA requirements for year 2 and 80% of net LRA requirements for year 3. No LSE cure period will be provided.
6	1-Nov		●					**CAISO** performs local RA Residual needs assessment for year 1 and announces results. Assessment is based on the need to achieve 100% of local RA need for year 1, including addressing any problematic sub-local-area constraints
7	1-Dec						●	**Central Buyer** procures the Residual, including ERR capacity not already procured by LSEs
8	21-Dec		●					**CAISO** performs final Year-Ahead local RA assessment to ensure that all Year 1 Local RA needs have been procured. Notifies LSEs of any deficiencies.
9	15-Jan		●		●	●		If needed, **CAISO** uses CPM backstop authority to procure the remaining required Year 1 Local RA resources, and **CAISO** accordingly allocates RA credits to **LSEs** and **Munis**
10	15-Jan		●	●	●	●		January Year 1 load migration forecasts submitted by **CPUC-Jurisdictional LSEs** and Munis to **CPUC** and/or **CEC**
11	15-Feb	●	●		●	●		January Year 1 Month Ahead RA filing (T-45). **CPUC-Jurisdictional LSEs** and **Munis** submit RA filings to **CPUC** and/or **CAISO**

CalCCA Proposed Local RA Timeline – April 1 Compliance Year



WITNESS QUALIFICATIONS

Lorenzo Kristov

Dr. Richard McCann

Shehzad Wadalawala

Résumé

Lorenzo Kristov, PhD

Principal Consultant – Electric System Policy, Structure, Market Design

PO Box 927, Davis, CA 95617, USA; email LKristov@cal.net; mobile +1 916 802-7059

Experience

Independent Consultant (December 2017 to present)

Current focus is on various aspects of power system evolution to high levels of renewable generation and distribution-connected energy resources (DER). Areas of expertise include: wholesale market design; market participation by DERs and DER aggregations; multi-use applications of DERs; coordination of transmission and distribution operations, markets and planning; distribution system operator (DSO) models for distribution utilities; transmission planning policy and alternative transmission and non-wires solutions; international comparison of TSO-DSO coordination models; community energy systems and microgrids; whole-system grid architecture.

Recent projects include:

Participation in and filing of individual comments on the Federal Energy Regulatory Commission technical conference on "Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators"; Docket RM18-9-000; June 2018

Co-author of "Alternative Transmission Solutions: A Roadmap to the CAISO Transmission Planning Process"; Center for Renewables Integration; March 2018; https://www.center4ri.org/publications/

Co-author of "Coordination of Distributed Energy Resources; International System Architecture Insights for Future Market Design"; prepared for the Australian Energy Market Operator (AEMO); May 2018

Individual comments to the California Public Utilities Commission in response to the October 31, 2017 informal public workshop on California Customer Choice; November 2017; http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Lorenzo%20Kristov%20Comments.pdf

California Independent System Operator (CAISO) (May 1999 to November 2017)

Principal, Market and Infrastructure Policy (2004-17); Manager, Market Design (1999-2004)

Led major market design and infrastructure policy initiatives, which entailed leading internal cross-departmental teams to develop proposals, conducting public stakeholder meetings to gather input, revising proposals to reflect stakeholder concerns, presenting final proposals to CAISO Board of Governors for approval, working with CAISO Legal department to prepare FERC filings (detailed proposal description and rationale, tariff revisions and expert testimony), appearing at FERC technical conferences, addressing FERC-ordered compliance requirements and supporting internal departments to implement FERC-approved market elements and tariff changes. Most initiatives were CAISO-initiated, but some were in compliance with new FERC rulemakings (e.g., Order 1000).

A central requirement of this position has been to apply whole-system thinking to structure each initiative to align the immediate needs of the problem to be addressed, the diverse objectives and concerns of the stakeholders, relevant regulatory constraints and requirements, and the priorities and responsibilities of the CAISO as a whole and its affected functional departments: grid operations, infrastructure planning, market performance.

Some specific major projects:

Initiated and led ongoing staff working group between CAISO and distribution utilities to identify needs and develop procedures for operational coordination at the transmission-distribution interfaces to enable distribution-connected resources (DER) and aggregations to participate in CAISO markets. (2016-17)

Represented CAISO in ongoing trans-Atlantic working group to describe and compare US and European approaches to transmission-distribution interface coordination with high DER. (2017)

Led CAISO-CPUC staff collaboration to develop a framework for multiple-use applications of energy storage, as part of the CPUC's Energy Storage Track 2 proceeding. (2016-17)

Led initiative to address cost allocation for existing transmission infrastructure and new projects under an expanded ISO/RTO structure for the western region. (2015-16)

Redesign of CAISO's new resource interconnection procedures to manage the large volume of new interconnection requests driven by anticipated procurement to meet California's Renewable Portfolio Standards (RPS), including the interconnection study process, management of the interconnection queue, and coordination between generator interconnection and transmission planning processes. (2011-12)

Redesign of CAISO's transmission planning process to address impacts of RPS procurement on transmission needs to deliver energy and capacity from renewable generation facilities; included addition of a new public-policy-driven category of transmission, coordination with state agencies to identify RPS procurement patterns that would drive transmission needs, and a competitive solicitation process for third party developers to build, own and operate transmission projects. (2009-10)

Initiated and led internal CAISO Strategic Roadmap Process, a cross-departmental team to map energy industry trends nationally and in the west and identify highest priority areas for CAISO focus in the coming years; performed in 2009, this roadmap led directly to the major redesigns of transmission planning and generator interconnection procedures noted above.

Comprehensive redesign of CAISO markets following the 2000 energy crisis to implement locational marginal pricing (LMP) market structure, including day-ahead and real-time markets, financial transmission rights, and integration of pre-existing bilateral transmission contracts. (2002-09)

California Energy Commission (CEC) (December 1994 to April 1999) Energy Economist

Represented the CEC in state proceedings and collaborative working groups to design the new provisions needed to implement the retail choice elements of California's electric restructuring legislation, AB-1890. Specific subjects included qualification of retail direct access providers, definition of "meter data management agent" (MDMA) function, and creation of distribution node identifier scheme for tracking changes of end-use customer, retail provider and metering device at each end-point of the distribution system. Facilitated several working group activities and co-authored working group reports; co-authored CEC regulatory filings at the CPUC.

Fulbright Scholar, Indonesia (April 1993 to December 1994)

As an independent researcher, met with Indonesian government officials, private companies, consultants, USAID and World Bank personnel to describe and assess economic and structural landscape for direct foreign investment in electric power infrastructure needed to support and sustain industrial growth.

Education

PhD Economics, University of California Davis, 1994

MS Statistics, North Carolina State University, 1969

BS Mathematics, Manhattan College, 1967

Relevant recent articles

Kristov et al (2017) "Coordination of transmission and distribution operations in a high distributed energy resource electric grid;" presenting results of collaborative working group between CAISO and electric distribution utilities; http://gridworks.org/wp-content/uploads/2017/06/MTS_CoordinationTransmissionReport.pdf

Kristov et al (2017) Primary author of "Comments of the California Independent System Operator Corporation" on FERC's Notice of Proposed Rulemaking (NOPR) to remove barriers to participation of electric storage resources and distributed energy resource aggregations in ISO/RTO wholesale markets; provides detailed descriptions of CAISO provisions for storage and DER aggregations to participate in wholesale market, and T-D interface coordination arrangements with distribution utilities; http://www.caiso.com/Documents/Feb13_2017_Comments-ElectricStorageParticipation_MarketsOperated_ISOs_RM16-23_AD16-20.pdf

Kristov, De Martini & Taft (2016) "Two visions of a transactive electric system," published in IEEE Power & Energy Magazine, May-June 2016; http://resnick.caltech.edu/docs/Two_Visions.pdf

Kristov (2015) "A future history of tomorrow's energy network," published in Public Utilities Fortnightly, May 2015; https://www.academia.edu/12419512/A_Future_History_of_Tomorrows_Energy_Network

De Martini & Kristov (2015) "Distribution systems in a high distributed energy resources future: planning, market design, operation and oversight," Lawrence Berkeley National Lab series on Future Electric Utility Regulation; https://emp.lbl.gov/sites/all/files/FEUR_2%20distribution%20systems%2020151023.pdf

Kristov et al (2017) Primary author of "How Transmission Cost Recovery Through the Transmission Access Charge Works Today: Background White Paper"; http://www.caiso.com/Documents/BackgroundWhitePaper-ReviewTransmissionAccessChargeStructure.pdf

Kristov et al (2016) Primary author of "Transmission Access Charge Options for Integrating New Participating Transmission Owners: Draft Regional Framework Proposal"; http://www.caiso.com/Documents/DraftRegionalFrameworkProposal-TransmissionAccessChargeOptions.pdf

Kristov & De Martini (2014) "21st Century Electric Distribution System Operations"; http://smart.caltech.edu/papers/21stCElectricSystemOperations050714.pdf

Taft, De Martini & Kristov (2015) "A reference model for distribution grid control in the 21st century," Pacific Northwest National Lab; https://gridarchitecture.pnnl.gov/media/advanced/Distribution%20Control%20Ref%20Model_v1.1_final.pdf

M.CUBED
POLICY ANALYSIS FOR THE PUBLIC AND PRIVATE SECTORS

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Professional Experience

M.Cubed, Partner, 1993-2008, 2014-present
Aspen Environmental Group, Senior Associate, 2008-2013
Foster Associates/Spectrum Economics/QED Research, Senior Economist, 1986-1992
Dames & Moore, Economist, 1985-1986

Academic Background

PhD, Agricultural and Resource Economics, University of California, Berkeley, 1998
MS, Agricultural and Resource Economics, University of California, Berkeley, 1990
MPP, Institute of Public Policy Studies, University of Michigan, 1986
BS, Political Economy of Natural Resources, University of California, Berkeley, 1981

Dr. McCann has analyzed many different aspects of energy utility and market operations in California. He has testified numerous times before the CPUC on impacts of electricity rates on agricultural groundwater pumping, reimbursement to master-metered manufactured housing community customers for utility services, competitive fuel choices, and proposed drought-mitigation policies. He has testified on the appropriate level of exit fees for community choice aggregators, and appropriate protection of solar project investment by customers. He also testified before the Federal Energy Regulatory Commission in the California energy crisis Refund Proceeding. He has worked with the California Energy Commission to estimate the costs for new alternative generating technologies and developing several system modeling tools for local capacity planning and renewable generation integration. For the CEC, he examined the potential consequences of decommissioning the dams on the Klamath River, and for the SWRCB, the changes in greenhouse gas emissions from hydro licensing conditions. He also led the modeling efforts on behalf of the California Public Utilities Commission to assess the environmental impacts of proposed generation plant divestitures.

Projects

Energy, Hydropower and Utilities

Regulatory Analysis and Support, Sonoma Clean Power (2016-present). Testifying at the California Public Utilities Commission (CPUC) in Pacific Gas and Electric's (PG&E) rate proceedings on the power charge indifference adjustment (PCIA) "exit" fee and other issues.

Regulatory Analysis and Support, CalChoice (2017). Testifying at the California Public Utilities Commission (CPUC) in Southern California Edison's (SCE) rate proceedings on the power charge indifference adjustment (PCIA) "exit" fee and other issues.

Agricultural Rate Setting Testimony, Agricultural Energy Consumers Association (1992-present). Testified about agricultural economic issues related to energy use, linkage to California water management policy, and utility rates in numerous proceedings at the California Public Utilities Commission, California Energy Commission, and California State Legislature. Analyzed various aspects of electric industry restructuring; proposed innovative pricing options; examined marginal cost principles and applications, and testified in a large number of energy related hearings. Developed innovative rate allocation methodology that incorporated regional marginal costs and value of service planning based on the Pacific Gas and Electric Co. Area Cost Study.

Testimony on Protecting Solar Project Investment by Customers, County of Santa Clara (2017-present). Testified before the California Public Utilities Commission on

Master-Meter Rate Setting Testimony, Western Manufactured Housing Communities Association (1998-present). Examined issues associated with the structure of and cost associated with providing electric service to master-metered mobile home parks. Testified in Pacific Gas and Electric Co., Southern California Edison Co., Southern California Gas Co. and San Diego Gas and Electric Co. rate proceedings on establishing "master-meter/submeter credits" provided to private mobile home park utility systems.

Master-Metered Utility Systems Transfer Program, Western Manufactured Housing Communities Association (2003-present). Prepared petition that opened a rulemaking to facilitate transfer of master-metered utility systems to serving utilities and testified in that proceeding. Testified before the State Legislature on proposed legislation. Persuaded all electric and gas utilities in California to institute a pilot program to convert 10% of privately-owned MHP systems to utility ownership.

Community Solar Gardens Testimony, Sierra Club (2014). Testified in Pacific Gas and Electric and Southern California Edison Green Tariff applications on changes needed to encourage the development of neighborhood and community-scale renewable distributed generation by allowing direct contracting and removing unnecessary transaction costs.

Time of Use Rates in California Residential Rates Rulemaking, Environmental Defense Fund (2013-2014). Modeled how increased penetration of TOU rates in the residential sector for all three investor-owned utilities would reduce peak and energy demand, reduce residential bills, and reduce utility costs. Changes in revenues and costs were developed from the utilities' most recent general rate case filings.

Southern California Edison v. State of Nevada Department of Taxation, Nevada Attorney General's Office (2013-2014). Testified on whether the sales tax imposed on coal delivered to SCE's Mohave Generating Station created a competitive disadvantage for SCE in the Western power market during the 1998-2000 period.

Professional Affiliations

American Agricultural Economics Association
Association of Environmental and Resource Economists
American Economics Association

Civic Activities

Member, City of Davis Utilities Rate Advisory Commission
Former Member, City of Davis Community Choice Energy Advisory Committee
Co-Chair, Cool Davis Energy Steering Committee
Member, Western Manufactured Housing Communities Association Utilities Task Force
Former Member, City of Davis Citizens Electricity Restructuring Task Force
Former Member, Yolo County Housing Commission
Member, Phi Beta Kappa Honorary Fraternity

SHEHZAD WADALAWALA

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Work Experience

The Energy Authority ("TEA"), Oakland, CA
Client Services Manager (7/16-present)

- Serve as Product Owner relating to the design, development and implementation of day-ahead and real time market services for TEA's CAISO operations;
- Work with clients and TEA's Portfolio Management and Analytics groups to define portfolio positions and develop hedging strategies
- Support client procurement activities by developing solicitation materials, including protocols, offer forms and contract templates and by providing assistance evaluating offers

SolarCity, San Francisco, CA
Sr. Manager, Grid Engineering Solutions (8/15-4/16)

- Led preparation of response to Innovative Storage Models RFI for ConEdison and Orange & Rockland
- Evaluated partnership opportunities with Community Choice Aggregations (CCAs), Electric Service Providers (ESPs), Municipal Utilities and Investor Owned Utilities (IOUs) focused on Distributed Energy Resources (DERs)
- Supported utility scale development team in understanding target wholesale markets

California Clean Power, Windsor, CA
Associate Director of Procurement (3/15-8/15)

- Authored key technical sections of Feasibility Reports for Community Choice Aggregation (CCA) formation; jurisdictions analyzed include Lake and Humboldt County
- Analyzed utility tariffs and filings to determine risks to company business model with particular focus on Non-Bypassable Charges (NBCs) such as the Power Charge Indifference Adjustment (PCIA) and Cost Allocation Mechanism (CAM)
- Identified potential Scheduling Coordinator (SC) Agents and negotiated contract for services

University of California Office of the President, Energy Services Unit, Oakland, CA
Associate Wholesale Electricity Program Manager (2/14-3/15)

- Led key implementation efforts for The Regents of the University of California to become its own Electric Service Provider (ESP) and serve its Direct Access campus accounts beginning January 2015
- Managed the Scheduling Coordinator (SC) contract including all relevant activities with the California Independent System Operator (CAISO) to be ready to submit daily load and generation schedules
- Solicited, selected and managed a Back Office provider; all eligible accounts were successfully transferred in January 2015
- Tracked, prepared and submitted numerous regulatory filings at the California Public Utilities Commission (CPUC), California Energy Commission (CEC), California Independent System Operator (CAISO), California Air Resources Board (ARB); all obtained approval
- Developed Request for Offer protocols for long-term solar solicitation; served on the evaluation committee and member of negotiating team that executed two 25-year Power Purchase Agreements (PPAs) totaling 80 MW of capacity

Pacific Gas and Electric Company – Portfolio Management, San Francisco, CA
Manager, Commodity Transactions (4/12-1/14)

- Managed a team of five employees responsible for:
  1) Preparation of Resource Adequacy (RA) Annual and Monthly Compliance Filings
  2) Execution of RA Request for Offers (RFOs)
  3) Implementation of the Electric Hedging Program
  4) Management of the Congestion Revenue Rights (CRRs) Portfolio
  5) Procurement of GHG Compliance Instruments
  6) Compliance with Energy Delivery Requirements for out-of-state Renewable Resources
- Prepared strategy and informational papers on highly technical material for members of the Risk Policy Committee (RPC)

Pacific Gas and Electric Company – Portfolio Management, San Francisco, CA
Principal, Short Term Portfolio Management (5/11-4/12)

- Led Resource Adequacy Request for Offers (RFOs); coordinated with Portfolio Management, Contract Management, Credit Risk, Legal and Compliance teams to ensure sufficient procurement to meet Resource Adequacy Requirements and ensure full cost recovery for procurement costs
- Coordinated talking points and written comments for AB32 Regulation ("Cap and Trade") for commercial team; resulted in favorable outcomes for PG&E most notably, obtaining fungibility of compliance instruments within compliance periods
- Contributed extensively to development of new Combined Heat and Power (CHP) Tolling Power Purchase Agreement (PPA), including recommending significant changes to Uninstructed Imbalance Energy and GHG Obligation Settlement sections and led development of a new Operational Flow Order (OFO) section in response to feedback from Electric Fuels Management about the increasing frequency of OFOs and associated commercial risks

Pacific Gas and Electric Company – Market Design and Monitoring, San Francisco, CA
Supervisor, Market Analysis (6/10-5/11)

- Supervised production, presentation and distribution of Market Redesign and Technology Upgrade (MRTU) Quarterly Report that included detailed discussion of CAISO market performance, key market issues, and financial risks for PG&E; presented to Senior Management
- Developed and supervised implementation of a comprehensive Convergence Bidding monitoring framework collaborating with Short Term Electric Supply; spearheaded analysis that identified gaming behavior and resulted in PG&E successfully advocating for suspension of convergence bidding at intertie locations.
- Educated Energy Procurement staff on CAISO markets through biweekly Market Talk Seminar Series that covered a range of CAISO topics including Convergence Bidding, Participating Intermittent Resource Program (PIRP), Oversupply Conditions and Negative Pricing, Congestion Revenue Rights (CRR's), Locational Marginal Prices (LMP's), Co-Optimization of Energy and Ancillary Services, Residual Unit Commitment (RUC), and Real Time Imbalance Energy Offset

Pacific Gas and Electric Company – Short Term Electric Supply, San Francisco, CA
Senior Analyst (7/08-6/10)

- Spearheaded development of business case for company participation in Convergence Bidding, including coordinating Risk Policy Committee (RPC) draft, contributing to upfront and achievable standards drafts, working with Information Technology and the Project Management Office to develop implementation cost estimates and collaborating with Market Risk Management, Market Design and Analysis and the Legal Department to identify potential risks
- Reformulated day-ahead optimization problem as a multi-day optimization reducing uneconomic cycling of thermal resources and improving commitment process for long-start resources
- Designed analytical tools and trading guidelines for real-time traders to manage price exposure

Pacific Gas and Electric Company – Quantitative Analysis, San Francisco, CA
Quantitative Analyst (6/04-7/08)

- Designed Microsoft Excel template that calculated energy values, risk-hedging metrics and generates summary sheets for physical assets (evaluated Gateway Generation Station project with template)
- Reformulated day-ahead scheduling optimization problem implemented in Short Term Electric Supply to include startup costs, ramping constraints and ancillary services increasing scheduling efficiency
- Developed gas asset strategy model to simulate cost outcomes for different portfolios of pipeline capacity and storage (model was used to evaluate investment in Ruby Pipeline capacity)

Education

University of California, Berkeley

PhD ABD Industrial Engineering and Operations Research (August 2003 - June 2008)
B.S. Industrial Engineering and Operations Research, August 2003; Public Policy Minor

Merits

8/99-5/03 **University of California Regents' & Chancellor's Scholarship**
10/01-5/03 **Alumni Emerging Leader Scholarship**

Exhibit B

Exhibit B

Analysis of Local Capacity Area Sub-Area Requirements

A. Scope of Resources

In the final decision for Track 1, a central buyer was described as "the solution most likely to provide cost efficiency, market certainty, reliability, administrative efficiency, and customer protection." Within this premise, CalCCA recognized the role of the Central Buyer to procure for two primary purposes. First, any efficient procurement solution should select all those resources that are essential, i.e. Essential Reliability Resources (ERRs) if not procured by any LSEs. These resources would necessarily have local market power and a Central Buyer with the ability to mitigate local market power, i.e. the CAISO is the most logical choice. Second, as a result of misalignment between LSE compliance obligations and the actual grid needs within the local areas, the Central Buyer should have an opportunity to procure a Residual amount, intentionally not procured by LSEs, to efficiently select resources in sub-areas that are needed and are not addressed by the procurement of ERRs or through bilateral contracting by LSEs. Since the CAISO has the most intimate knowledge of grid needs and relative effectiveness of resources, again, the CAISO is the most logical choice for the Central Buyer for the Residual amount.

In this section, CalCCA presents analysis aimed at answering two key questions:

(1) How many resources have significant local market power, i.e. are ERRs?
(2) How significant is the risk of inefficient procurement that could result in collective deficiencies?

Throughout the discussion, we also present observations and possible recommendations on how to ensure the continued success of the Local RA program.

Background

In its annual technical study, the CAISO summarizes Local Area requirements for ten Local Capacity Areas shown below.

2019 Local Capacity Requirements

	Qualifying Capacity			2019 LCR Need Based on Category B***			2019 LCR Need Based on Category C*** with operating procedure		
Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	0	202	202	116	0	**116**	165	0	**165**
North Coast / North Bay	119	771	890	689	0	**689**	689	0	**689**
Sierra	1146	1004	2150	1362	0	**1362**	1964	283*	**2247**
Stockton	144	489	633	405	5*	**410**	427	350*	**777**
Greater Bay	628	6426	7054	3670	0	**3670**	4461	0	**4461**
Greater Fresno	340	3098	3438	1406	0	**1406**	1670	1*	**1671**
Kern	13	462	475	148	6*	**154**	472	6*	**478**
LA Basin	1445	8780	10225	7968	0	**7968**	8116	0	**8116**
Big Creek/ Ventura	424	4649	5073	2333	0	**2333**	2614	0	**2614**
San Diego/ Imperial Valley	106	4252	4358	4026	0	**4026**	4026	0	**4026**
Total	4365	30133	34498	22123	11	**22134**	24604	640	**25244**

As far as compliance, LSEs serving customers in PG&E's service territory must comply with two Local RA obligations, Bay Area and Other PG&E Areas. The latter is comprised of Humboldt, North Coast/North Bay, Sierra, Stockton, Greater Fresno, Kern. LSEs serving customers in SCE's territory must comply with two Local RA obligations, LA Basin and Big Creek/Ventura. LSEs serving customers in SDG&E's territory must comply with a single Local RA obligation, San Diego/Imperial Valley. Within the Local Areas above, there are further sub-areas with their own requirements that are discussed in detail in the CAISO 2019 Local Capacity Technical Analysis.

Analysis

CalCCA performed an initial analysis to estimate the volumes of ERRs using CAISO's 2019 Local Capacity Technical Analysis and the most recent NQC list posted on the CAISO's website dated July 16, 2018. We note that the current NQC list has a different level of Qualifying Capacity than the CAISO's report for the local areas in 2019, so we would expect the actual volumes of ERRs to be slightly different when accounting for retirements and/or new resources. Further, CalCCA treated all MWs within a sub-area as equivalent and did not perform any effectiveness factor analysis, so the actual amount of ERRs could be somewhat larger where sub-area constraints are applicable. Nonetheless, we think that the preliminary analysis is still a reasonable estimate and starting point to frame the questions regarding how many resources have significant local market power and how much inefficient procurement is possible.

To determine the ERRs, for each sub-area, we identified a threshold size for which a resource would be pivotal by comparing the total supply to the total need. For example, if Local Area A has a Local Capacity Requirement (LCR) of 100 MW and 150 MW of total supply, then an individual resource with size exceeding 50 MW (the "ERR threshold") would be pivotal as the LCR could not be met, i.e. the area would be deficient, without at least some of its capacity. If Local Area A had two resources of 60 MW each, then both are essential and would be identified as ERRs. We then designated each resource that addresses the sub-area need with an NQC exceeding that threshold as an ERR. We found that of the 38,711[1] MW of Local RA, 5,392 MW would obtain an ERR designation[2]. The 5,392 MW represents 21% of the overall 2019 LCR Need of 25,244 MW based on Category C[3].

Table 1 – Essential Reliability Resources by Local Area

Local Area Name	2019 Qualifying Capacity	2019 Category C	Current NQC List	ERR Volume (2019 study)
Humboldt	202	165	202	163
North Coast/North Bay	890	689	865	512
Sierra	2150	2247	2170	1574
Stockton	633	777	635	630
Greater Bay	7054	4461	9764	813
Greater Fresno	3438	1671	3281	4
Kern	475	478	472	472
LA Basin	10225	8116	10799	0
Big Creek/Ventura	5073	2614	5573	1035
San Diego/Imperial Valley	4358	4026	4950	190
Total	34498	25244	38711	**5392**

Examining Table 1, the majority of the ERRs (4,167 MW) are located within PG&E's service territory while only 1,035 MW are located in SCE's service territory and 190 MW are located in SDG&E's service territory.

Table 2 – Essential Reliability Resources relative to Local Capacity Requirements

Local Area	ERR	LCR	Percent
Other PG&E	3354	6027	55.7%
Greater Bay	813	4461	18.2%
LA Basin	0	8116	0.0%
Big Creek/Ventura	1035	2614	39.6%
San Diego/Imperial Valley	190	4026	4.7%

[1] We note that the NQC list still contains Local RA resources that have already retired. For example, the NQC list still includes Moss Landing 6 and 7, Pittsburg 5, 6 and 7 which represent 2668 MW. Retired resources were excluded from sub-area analysis.

[2] CalCCA's estimates from this analysis do not consider how many resources would receive an ERR designation in 2019 based on being pivotal supplier in 2020 or 2021 because the CAISO performed those studies in 2015 and 2016 respectively and assumptions are likely not consistent with the 2019 study performed earlier this year

[3] Because several sub-areas are deficient, the total LCR allocated to LSEs for 2019 is 24,604 MW.

Given the overall complexity of PG&E and its sub-areas, we first start with analyzing SDG&E and SCE's local areas.

SAN DIEGO GAS & ELECTRIC COMPANY

1. **How many resources have significant local market power, i.e. are ERRs?**

The CAISO study of San Diego/Imperial Valley Local Area included the El Cajon, Mission, Esco, Pala, Border, Miramar and San Diego sub-areas. Of these, Mission, Esco and Miramar were eliminated due to transmission projects. Among the constrained sub-areas, CalCCA identifies 190 MW of ERR capacity.

El Cajon has a LCR of 88 MW and three resources, El Cajon Energy Center (48.1 MW), Cuyamaca Peak Energy Plant (45.42 MW), and Eastern Bess 1 (7.5 MW). With 101 MW total available, an individual resource would have to at least 13 MW of size to have market power and be designated as an ERR. The "ERR threshold" of 13 MW designates El Cajon Energy Center and Cuyamaca Peak Energy Plant as ERRs (94 MW in total).

Pala has an LCR of 10 MW and four resources, Orange Grove Energy Center (96 MW), Cole Grade (0.96 MW), Valley Center 1 (1.05 MW) and Valley Center 2 (2.03 MW). With 100 MW total available, the ERR threshold of 90 MW designates Orange Grove Energy Center as an ERR.

Border has an LCR of 100 MW and eight resources totaling 179 MW. With an ERR threshold of 79 MW, no resources would be designated as an ERR due to the Border sub-area needs.

San Diego has an LCR of 2,417 MW and a total of 3,446 MW of capacity. With an ERR threshold of 1,029 MW, no resources would be designated as an ERR due to the San Diego sub-area needs.

For the overall San Diego/Imperial Valley Local Area, the LCR is 4,026 MW and there is a total of 4,950 MW of capacity. With an ERR threshold of 924 MW, no resources would be designated as an ERR due to the overall area need. However, recognizing the differences between the NQC list and the CAISO's 2019 Local Capacity Technical Analysis, if the available Qualifying Capacity were 4,358 MW as is indicated in the CAISO report instead of the 4,950 in the NQC list, then with a lower ERR threshold of 332 MW, the three largest resources in the San Diego/Imperial Valley local area, Otay Mesa Energy Center (604 MW), TDM (593 MW) and Palomar Energy Center (566 MW), would receive the ERR designation.

2. **How significant is the risk of inefficient procurement that could result in collective deficiencies?**

For the San Diego/Imperial Valley Local Area, the risk of inefficient procurement resulting in collective deficiencies is relatively small. Assuming no resources were under contract and under the current Local RA construct, the most inefficient selection of resources meeting the San Diego/Imperial Valley LCR of 4,026 MW would result in the three ERR resources remaining uncontracted as well as all eight resources that meet the Border sub-area need. This would result in an overall deficiency of 198 MW (88 MW El Cajon, 10 MW Pala, 100 MW Border), or 5 percent of the total LCR. Total backstop procurement by the CAISO in this circumstance would likely be greater than 198 MW, however, as Orange Grove (96 MW) would be unlikely to accept a 10 MW CPM designation with its remaining capacity uncontracted.

While the above analysis represents the most inefficient outcome, the actual risk based on current contracts is less. The Staff Proposal included an assessment of resources under contract demonstrating that the actual problem for 2019, 2022, and 2023 is limited to the Border sub-area where no resources are under contract. For the El Cajon and Pala sub-areas all existing resources are under contract.[4] In other words, for these years only 100 MW, or 2.5 percent of resources, is at risk of requiring collective-deficiency procurement.

SOUTHERN CALIFORNIA EDISON COMPANY

1. How many resources have significant local market power, i.e. are ERRs?

a. *LA Basin*

The CAISO study of the LA Basin Local Area included the El Nido, Western LA Basin, Eastern LA Basin, West of Devers, Valley, and Valley-Devers sub-areas. Of these, West of Devers, Valley and Valley-Devers are all satisfied by the need in the larger Eastern LA Basin sub-area. Overall, among the constrained sub-areas there is no ERR capacity identified.

El Nido has an LCR of 231 MW and four resources, Chevron U.S.A. Units 1 and 2 Aggregate (10.99 MW), El Segundo Energy Center 5/6 (263 MW), El Segundo Energy Center 7/8 (264 MW) and MWD Venice Hydroelectric Recovery Plant (0 MW). With 538 MW total available, and a resulting ERR threshold of 307 MW, no resources would be designated as ERRs.

Western LA Basin has an LCR of 3,993 MW and a total of 6,386 MW of capacity. With an ERR threshold of 2,393 MW, no resources would be designated as ERRs.

Eastern LA Basin has an LCR of 2,956 MW and a total of 3,761 MW of capacity. With an ERR threshold of 805 MW, no resources would be designated as ERRs.

b. *Big Creek/Ventura*

The CAISO study of the Big Creek/Ventura Local Area included the Rector, Vestal, Santa Clara, and Moorpark, sub-areas. Of these, Rector sub-area needs are met by the larger Vestal sub-area. Overall, among the constrained sub-areas there is 1,035 MW of ERR capacity identified.

Vestal has an LCR of 621 MW and a total of 1,116 MW of capacity. The ERR threshold of 495 MW designates Big Creek Hydro Project PSP (801 MW) as an ERR.

[4] The calculations below are for 2019 but the same logic applies for 2022 and 2023:
For El Cajon, the Staff Report indicates for that 115% of the 88 MW requirement is under contract = 101 MW
For Pala, the Staff Report indicates that 1000% of the 10 MW requirement is under contract = 100 MW

Santa Clara has an LCR of 237 MW and a total of 245 MW of capacity. With an ERR threshold of 8 MW, 234 MW of ERR capacity would be designated. Of note, the Ellwood facility (54 MW) that the CAISO has approved for an RMR contract for 2019 is located in this sub-area.

Moorpark has an LCR of 433 MW and a total of 1,768 MW of capacity. With an ERR threshold of 1,335 MW, no resources would be designated as ERRs. Of note, the Ormond units make up 1,516 MW of the total capacity in the Moorpark sub-area. Without both units, the area would be deficient. One plant is scheduled to retire and the CAISO has approved an RMR contract for 2019 for the other.

2. **How significant is the risk of inefficient procurement that could result in collective deficiencies?**

   a. *LA Basin*

For the LA Basin Local Area, the risk of inefficient procurement resulting in collective deficiencies is relatively large assuming no resources currently under contract and relatively small when considering existing contracts. Assuming no resources were under contract and under the current Local RA construct, the most inefficient selection of resources meeting LA Basin LCR of 8,116 MW would be by procuring all resources in the Western LA Basin (6386 MW) before starting to meet the Eastern LA Basin need (procure 1,730 MW of Eastern LA Basin to meet 8,116 MW LA Basin LCR). The inefficient procurement would result in a deficiency of 1,226 MW in the Eastern LA Basin or 15 percent of the LA Basin LCR. The counterintuitive result is that because Western LA Basin has excess supply, it creates an opportunity for LSEs to meet their LA Basin compliance obligation without meeting the Eastern LA Basin sub-area need. Given that both the Western LA Basin and Eastern LA Basin are relatively well-supplied, one option is to disaggregate the LA Basin requirement to prevent this theoretical possibility. Another option is to place percentage limits on sub-area procurement.

   b. *Big Creek/Ventura*

For Big Creek/Ventura Local Area, the risk of inefficient procurement is relatively high assuming no contracting but less so when considering existing contracts. Assuming no resources were under contract and under the current Local RA construct, the most inefficient selection of resources meeting the Big Creek/Ventura LCR of 2,614 MW would be by procuring all 1,768 MW of resources in Ventura (would meet Santa Clara and Moorpark sub-area needs) and then 846 MW of Big Creek resources that do not address the Vestal sub-area needs. This would result in a deficiency of 621 MW, or 23 percent of the Big Creek/Ventura LCR. Total backstop procurement by the CAISO in this circumstance would likely be greater than 621 MW, however, as Big Creek Hydro Project PSP (801 MW) would be required and may not accept a CPM designation for only a portion of its capacity.

In consideration of existing contracting, it appears the opposite situation has occurred where contracting in 2019, 2022 and 2023 is concentrated in the Big Creek and Vestal areas at the expense of the Santa Clara and Moorpark sub-areas within Ventura. To address this deficiency, the CAISO has approved RMR contracts for 2019 with the Ellwood plant located in the Santa Clara sub-area and one of the two Ormond units located in the Moorpark sub-area. These commitments represent 795[5] MW, or 30% of the Big Creek/Ventura LCR need. For subsequent years, SCE is in the early stages of procuring preferred resources and storage to meet the Santa Clara sub-area need. The new resources are expected to be online in 2021. In addition, the Pardee-Moorpark 230 kV transmission project was approved in March to address the local capacity concern in the Moorpark sub-area. The project has an in-service date of December 31, 2020.

Similar to LA Basin, one option is to disaggregate the Big Creek/Ventura Local Areas while another is to place percentage caps on how much LSEs can procure in specific sub-areas.

PACIFIC GAS AND ELECTRIC COMPANY

1. How many resources have significant local market power, i.e. are ERRs?

a. *Greater Bay*

The CAISO study of the Greater Bay Local Area included the Oakland, Llagas, San Jose, South Bay, Contra Costa, Ames/Pittsburg/Oakland combined sub-areas. Overall, among the constrained sub-areas there is 813 MW of ERR capacity identified.

Oakland has an LCR of 20 MW and a total of 214 MW of capacity. With an ERR threshold of 194 MW, no resources would be designated as an ERR.

Llagas has an LCR of 77 MW and a total of 247 MW of capacity. With an ERR threshold of 170 MW, no resources would be designated as an ERR.

San Jose has an LCR of 177 MW and a total of 528 MW of capacity. With an ERR threshold of 351 MW, no resources would be designated as an ERR.

South Bay has an LCR of 1,653 MW and a total of 2,364 MW of capacity. With an ERR threshold of 711 MW, no resources would be designated as an ERR.

Contra Costa has an LCR of 1,067 MW and a total of 2,189 MW of capacity. With an ERR threshold of 1,122 MW, no resources would be designated as an ERR.

Ames/Pittsburg/Oakland combined has an LCR of 1,741 MW and a total of 2,479 MW of capacity. The ERR threshold of 738 MW designates Delta Energy Center Aggregate (813 MW) as an ERR.

b. *Other PG&E Areas*

For the Other PG&E Areas, we present the summary results rather than provide a detailed assessment of each local area and its associated sub-areas. Overall, there is 3,354 MW of ERR

[5] Ellwood = 54 MW and assuming the smaller Ormond Unit with 741 MW of NQC

capacity. Among Humboldt, North Coast/North Bay, Sierra, Stockton, Greater Fresno and Kern local areas, only Greater Fresno has a high level of competition. Excluding Greater Fresno, of the 4,344 MW capacity located in the Other PG&E Areas, 3,350 MW would be designated as ERR. Within the Stockton and Kern local areas all resources would be ERRs except one in located in Stockton. In contrast, Greater Fresno, has only 4 MW of ERR out of a total capacity of 3,281 MW.

2. **How significant is the risk of inefficient procurement that could result in collective deficiencies?**

   a. *Greater Bay*

For the Greater Bay Local Area, the risk of inefficient procurement resulting in collective deficiencies is relatively large assuming no resources currently under contract. While based on contracting information for 2019 the risk is relatively small, the Staff Proposal did not reveal contracting information for the San Jose or South Bay sub-areas for 2022 and 2023 necessary to make an assessment. Assuming no resources were under contract and under the current Local RA construct, one of the most inefficient selection of resources meeting the Greater Bay LCR of 4,461 MW would be by procuring all resources in the Contra Costa sub-area (2,189 MW) then only resources in the South Bay (procure 2,272 MW of South Bay to meet 4,461 MW Greater Bay LCR). The inefficient procurement would result in a deficiency of 1,741 MW, for Ames/Pittsburg/Oakland combined representing 39 percent of the Greater Bay LCR. The counterintuitive result is that because Contra Costa has excess supply, it creates an opportunity for LSEs to meet their Greater Bay compliance obligation without necessarily meeting the South Bay or Ames/Pittsburg/Oakland combined sub-areas.

Unlike the LA Basin example, disaggregation of the Greater Bay is not as straightforward because the South Bay and Ames/Pittsburg/Oakland sub-areas rely on several large facilities that could exert market power without the aggregation of the sub-areas. Given that the Marsh Landing facility (784 MW) is a CAM resource and Gateway Generating Station (564 MW) is UOG, it is almost assured that surplus RA from the Contra Costa sub-area will be represented in the aggregate portfolio provided by LSEs in PG&E's service area contributing to the likelihood of collective deficiencies.

   b. *Other PG&E Areas*

For Other PG&E Areas, the risk of inefficient procurement is high because of the large excess supply in the Greater Fresno area. The most inefficient selection of resources would be to select all resources in the Greater Fresno (3,281 MW) followed by all resources in North Coast/North Bay (865 MW), all resources in Humboldt (202 MW) and then the rest (1,679 MW) as inefficiently as possible within the Sierra local area. This would result in a total deficiency of 1,670 MW, or 28 percent, including a complete deficiency in Stockton (630 MW) and Kern (472 MW) and a partial deficiency in Sierra (568 MW).

Similar to Greater Bay Area, the approach to disaggregate the Other PG&E Areas and excluding Greater Fresno is not straightforward because of the concentration of market power that would remain. Looking at forward contracting in the Staff Proposal, there is a surplus of resources under contract in the Greater Fresno area while the North Coast/North Bay, Sierra, Stockton and Kern are under-contracted.

Conclusions

The analysis suggests that the potential for inefficient procurement varies widely among the three IOU territories, ranging from 190 to 3,411 in MW terms, and between 5 (SDG&E) and 32.5 (PG&E) as percentages of the LCR.

SDG&E has relatively simple sub-areas and few opportunities for inefficient procurement. Even a modest amount of Residual procurement by a Central Buyer would ensure that all sub-area requirements would be met.

SCE while more complicated than SDG&E still has fairly straightforward sub-areas. With respect to addressing local area reliability and market power, the Santa Clara sub-area within the Big Creek/Ventura Local area necessarily needs more resources or transmission upgrades. In the short term, all ERRs should be maintained while addressing such needs in the longer-term should necessarily be part of the IRP and/or TPP. With respect to inefficient procurement, given the high level of competition, a viable option is disaggregating both Local RA areas or placing some limitation on how much can be procured in any particular sub-area. As a result, there would be little opportunity for inefficient procurement resulting in collective deficiencies. With this change, even a modest level of Residual procurement by a Central Buyer should be sufficient for SCE's service territory.

PG&E is the most challenging in the short term because of the level of local market power. In the short term, all ERRs should be maintained. Beyond that, disaggregation of the local areas may be problematic for LSE procurement given the concentration of market power. However, there is a tradeoff in maintaining aggregated local areas for the purposes of compliance and limiting market power because it increases the likelihood of collective deficiencies. One short term possibility is for the CPUC to disincentivize procurement of resources located in the Greater Fresno area that only meet the Wilson sub-area need. Since the Greater Fresno area has significant excess supply and all resources meet the Wilson sub-area need, it is more efficient to procure the resources that also meet Hanford, Coalinga, Borden, Reedley, or Herndon sub-area needs. Another option is under the CalCCA Transition Program framework to have a relatively higher level of Residual procurement by the Central Buyer for Other PG&E Areas as compared to other Local Areas. In the long-term, addressing market power should fall into the purview of the IRP and/or TPP. For example, five Sierra sub-areas, Placerville, Placer, Bogue, Drum-Rio Oso and South of Palermo, where 1,574 MW of ERRs are identified, will be eliminated in the next 10 years[6]. As local market power and sub-area constraints are addressed over time, disaggregation of the Other PG&E Areas is a viable option to reduce and potentially eliminate inefficient procurement.

[6] Slide 6 - https://www.caiso.com/Documents/Presentation-LocalCapacityRequirementReductionStudy.pdf

**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)

**REPLY TO JOINT IOUS' RESPONSE TO MOTION OF THE CCA PARTIES
TO SUBMIT REQUESTED INFORMATION UNDER SEAL**

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Pioneer Community Energy,
Redwood Coast Energy Authority,
Silicon Valley Clean Energy Authority,
and Sonoma Clean Power Authority
(collectively, "CCA Parties")

July 26, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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REPLY TO JOINT IOUS' RESPONSE TO MOTION OF THE CCA PARTIES TO SUBMIT REQUESTED INFORMATION UNDER SEAL

In accordance with Rule 11.1(f) of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the CCA Parties reply to the July 19, 2018 Response filed jointly by Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company (collectively "Joint IOUs") to the Motion of the CCA Parties to Submit Requested Information Under Seal.[1] The CCA Parties submit this Reply pursuant to the authorization granted by Administrative Law Judge Mason in an email ruling dated July 23, 2018.

I. INTRODUCTION

As noted in the CCA Parties' Motion, the *Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2018*

[1] Pursuant to Rule 1.8(d), Apple Valley Choice Energy, Marin Clean Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy, Pioneer Community Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority have authorized the undersigned counsel to sign and file this reply on their behalf.

Renewables Portfolio Standard Procurement Plans, dated June 21, 2018 ("Procurement Plan Ruling"), requests that Community Choice Aggregators submit certain cost quantification information to the Commission in order to help it meet "its system planning and Integrated Resource Planning obligations."[2] This same request was made in 2017, but no entity submitted this information. The primary purpose of the CCA Parties' Motion is to obtain necessary guidance from the Commission on the ability of and procedure for a Community Choice Aggregator to submit portions of this cost quantification data confidentially. The CCA Parties note that this information is ***requested*** and not mandated by the Commission. By not providing the necessary guidance or by imposing unreasonably burdensome requirements, the Commission will simply discourage the submission of this information.

II. REPLY TO JOINT IOU'S RESPONSE

A. The CCA Parties Agree that the Same Process for Claiming Confidentiality for Data Should Apply to All Retail Sellers.

In their Response, the Joint IOUs state that the Commission's confidentiality rules should apply equally to all retail sellers.[3] Decision ("D.") 06-06-066 clarifies that the same *process* for claiming confidentiality applies all retail sellers.[4] The CCA Parties fully agree that the process should be the same and the CCA Parties simply seek necessary guidance to effectuate this consistent treatment. As the Commission has acknowledged, the confidentiality matrices in D.06-06-066 do not specifically apply to Community Choice Aggregators, and instead only expressly apply to the IOUs and the Electric Service Providers ("ESPs").[5] This means that

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2 Procurement Plan Ruling at 6.

3 Joint IOUs' Response at 2.

4 D.06-06-066 at 52-53.

5 *See Administrative Law Judge's Ruling Granting the California Community Choice Association's Request to Submit Information Under Seal*, dated May 18, 2018 at 1-2 (R.17-09-020).

Community Choice Aggregators do not automatically receive matrix treatment for the categories of information identified in the ESP and IOU matrices. Until the Commission formally and comprehensively resolves the applicability of confidentiality requirements as applied to the submission of data by Community Choice Aggregators, this guidance will need to be provided on an issue by issue basis.

The CCA Parties simply seek guidance that the Matrix Categories identified in the Motion apply to Community Choice Aggregators.[6] That clarification will allow individual Community Choice Aggregators to submit this requested data under seal in the same manner and through the same process as ESPs and IOUs.

B. The CCA Parties Clarify that They Seek Matrix Treatment for the Identified Categories and that Each Community Choice Aggregator Submitting Data Under Seal Would Need to Meet the Requirements of D.08-04-023.

The Response of the Joint IOUs asserts that the CCA Parties have not complied with the requirements of D.08-04-023 to demonstrate that the data meets certain requirements, including that the data has not already been made public and cannot otherwise be aggregated. The CCA Parties clarify that they seek confirmation that the matrix treatment that currently applies to IOUs and ESPs would also apply to Community Choice Aggregators for specific categories noted in the CCA Parties' Motion. Any Community Choice Aggregator submitting data under seal as part of its procurement plan or through a separate filing would need to meet the requirements of D.08-04-023, including a demonstration that the information is not already public and cannot

[6] The specific categories are the following: (1) ESP Matrix Item IV(C) and IOU Matrix Item V(C), specifying that the front three years of load serving entity total energy forecast may be confidential; (2) ESP Matrix Item I(C) and IOU Matrix Sections VII(F) and (G), specifying that bilateral contract financial terms, such as those dealing with pricing or security deposits, may be confidential for the earlier of either three years or one year after the contract expires; and (3) IOU Matrix Section II(B)(4), specifying that non-Qualifying Facility bilateral contract forecasts of cost by resource category is confidential for three years.

otherwise protected in a way that allows partial disclosure. The CCA Parties simply seek clarification that the same process that currently applies to IOUs and ESPs also applies to Community Choice Aggregators.

C. A Ruling by the Commission Is Necessary to Ensure that a Community Choice Aggregator Will Not Waive Protected Status for the Information Submitted to the Commission.

Community Choice Aggregators are distinct from IOUs and most ESPs in that they are public agencies and are subject to the Public Records Act. Pursuant to Government Code section 6254.5, a public agency is deemed to waive the exemptions that otherwise protect information from disclosure if the public agency provides that information to a member of the public. However, there is no waiver if the disclosure is to a governmental agency that has agreed to treat the information as confidential.[7] If a Community Choice Aggregator provides otherwise confidential data to the Commission without confirmation that the material will be treated as confidential, the Community Choice Aggregator risks waiving the confidential status of this information.

A ruling providing guidance that the Commission will apply matrix treatment for the requested categories to Community Choice Aggregators will provide the necessary clarification that the Community Choice Aggregators can submit information to the Commission under seal without risking waiving the protected status of this information.

[7] *See* CCA Parties Motion at 4, note 9 (citing Cal. Pub. Util. Code § 6254.5(e)).

D. The Commission Can and Should Provide Flexibility to Community Choice Aggregators to Submit this Information in the Least Burdensome Manner Possible.

The Joint IOUs' Response argues that each retail seller "should report its own data in its RPS plan."[8] The Joint IOUs also assert that all retail seller cost quantification should be made public in the same manner, either aggregated or individually. The argument that this information must be submitted and reported equally is unpersuasive. The CCA parties note that this information is requested on a *voluntary* basis from Community Choice Aggregators, while this information is *mandatory* for IOUs. This information is mandatory for IOUs because the Commission needs the IOU data to comply with the statutory requirement to report to the Legislature pursuant to Public Utilities Code sections 913.3 and 913.4 on the eligible renewable energy resource contracts ***approved by the Commission***, as well as information on IOU revenue requirement impacts, and the progress of the IOUs in meeting the RPS.

The Commission does not approve Community Choice Aggregator contracts, and Community Choice Aggregator information is not otherwise required for the Commission to comply with Public Utilities Code sections 913.3 or 913.4. Instead, this information is requested by the Commission because it would be useful for more generalized planning purposes. Therefore, the cost quantification data request from Community Choice Aggregators serves a fundamentally different purpose from the statutorily mandated cost quantification data of the IOUs. In light of this significant difference, it is reasonable for the Commission to provide broad flexibility to the Community Choice Aggregators to submit this information in the least burdensome manner that still meets the goals of the Commission.

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[8] Joint IOUs' Response at 4.

As the CCA Parties previously noted, there may be alternative methods including aggregating data across multiple Community Choice Aggregators, that could avoid the need to submit this data under seal. It would be the obligation of the Community Choice Aggregators to ensure that any process to aggregate such data does not inadvertently waive confidentiality.

II. CONCLUSION

The CCA Parties urge the Commission to provide the necessary guidance to Community Choice Aggregators to help facility the voluntary submission of the requested cost quantification data to the Commission.

Dated: July 26, 2018

Respectfully submitted,

/s/ Justin Wynne

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Monterey Bay Community Power Authority,
Peninsula Clean Energy,
Pioneer Community Energy,
Redwood Coast Energy Authority,
Silicon Valley Clean Energy Authority,
and Sonoma Clean Power Authority

VERIFICATION

I, Justin Wynne, have been authorized in connection with the filing and service of the *Reply to Joint IOUs' Response to Motion of the CCA Parties to Submit Request Information Under Seal* ("Reply") to make this required Verification under Rules 1.8(d) and 1.11(d) as follows: as an attorney for the cities of Lancaster, Pico Rivera, San Jacinto, and Rancho Mirage, Apple Valley Choice Energy, Marin Clean Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy, Pioneer Community Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy Authority, and Sonoma Clean Power Authority ("CCA Parties"). The CCA Parties are absent from the County of Sacramento, California, where I have my principal office. I declare under penalty of perjury that the statements in the Motion 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 July 26, 2018, at Sacramento, California.

/s/ Justin Wynne

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