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County of Santa Barbara Board of Supervisors
Jennifer Cregar, Project Supervisor, Energy and Sustainability Initiatives
County of Santa Barbara
Via email: info@centralcoastpower.org

Re: Central Coast Power Community Choice Energy Feasibility Study available at: http://centralcoastpower.org/resources.org

On September 11, 2017, Central Coast Power issued a notice announcing the availability for public comment of the Community Choice Energy Feasibility Study and plans by the County of Santa Barbara Board of Supervisors to consider the study on October 3. The study evaluates the feasibility of creating a new CCE program for the Tri-County Region including San Luis Obispo, Santa Barbara, and Ventura Counties.

According to the announcement:

> The feasibility study and subsequent peer review suggest that a newly created regional CCE program spanning Santa Barbara, San Luis Obispo, and Ventura Counties is likely not a viable venture in terms of the CCE program's ability to provide competitive rates and remain a solvent organization. The peer review preliminarily suggests that there may be feasible CCE options for some local governments in Pacific Gas and Electric Company (PG&E) territory. The study did not evaluate the potential for one or more local governments to join an existing CCE program.

The Feasibility Study's design is fundamentally sound in nearly all respects. The conservative approach to the potential financial risks to participating communities from formation and participation in Central Coast Power is appropriate. However, there are a number of critical limitations in the study that need to be addressed before the sponsoring counties can reasonably conclude whether the CCE program is likely to be a financially viable enterprise. These limitations include:

- a cost- rather than market-based approach toward projecting CCE renewable energy costs for the 2020-2030 study period;
- overly pessimistic estimates for the Power Cost Indifference Adjustment (PCIA) charges; and

- failure to consider the long-term cost of capital advantages of publicly-owned enterprises over their investor-owned counterparts when financing new power supply resources.

The preliminary analyses outlined below indicate that CCP may be financially viable based on lower renewable energy costs and more reasonable estimates of the PCIA. The combined effect of both of these adjustments amount to roughly $35 per MWH. However, more detailed study of both cost components is required.

I would also emphasize that should the participating jurisdictions decide to pursue opportunities for direct ownership of power supply resources, as is common for comparably sized publicly-owned utilities and municipal joint-action agencies, long term savings for the residents and businesses located within the Advisory Working Group jurisdictions should be achievable. Generation resources are highly capital intensive. The competitive advantage of publicly-owned enterprises that invest to serve their communities should not be ignored.

Each of these limitations should be addressed and incorporated into an updated feasibility study prior to any decision to proceed - or not proceed - with formation of the Central Coast Power enterprise and development of a detailed business plan.

As a final note: there are a wealth of resources available from individual utilities, associations and consultants that serve the public power sector, should the participating jurisdictions decide to proceed.

CCE Power Supply Costs

First, the study's conclusion that a regional CCE program is unlikely to be financially viable results directly from the faulty methodology adopted to project the cost of renewable energy procured by the CCP over the study period. Historical renewable purchased power agreement costs, even those contracted as recently as 2016, are unlikely to provide an accurate assessment of going forward power supply costs for the CCP. (The opposite is true for PG&E and SCE, which have large portfolios of owned and PPA contract resources. These sunk costs drive their power supply costs and the PCIA adjustments).

This methodological limitation is highlighted by the discussion at pages II-41 to II-42. Table 23 shows a California-Specific Renewable Power Purchase Agreement Price Forecast of $82.72 per MWH for 2020. In marked contrast, the Advisory Working Group, based on an informal discussions with operational CCAs in California, reported renewable energy prices under $50 per MWH. Table 25 at page II-42 shows "Observed Pricing Responses Provided to the AWG by Operating CCAs, June 2017" of $28-38 for 1 to 3-year terms; average mid-$30s for natural gas resources and $40-$51 for 1 to 3-year terms; average high $40s for Category 1 Renewables. Simple back-of-the envelop calculations would show an energy resource portfolio comprised of

50% renewables and 50% natural gas energy under $45 per MWH. Again for back-of-the envelop purposes, we can use Willdan's estimates for Resource Adequacy, CAISO Day-Ahead and Real-Time markets and Storage costs to derive a non-energy adder of $9.55 per MWH. The combined total PPA cost of $54 per MWH is roughly $20 less than the $74.36 per MWH amount shown for 2020 in Table 49 for the AWG Middle of The Road, Base Portfolio scenario (page II-74).

The Study concludes at page II-58 that:

> The price premium for higher renewable content requirements cannot be known without a procurement process to validate the power purchase costs estimates in Section II.B. The Advisory Working Group should proceed with a Request for Information to solicit pricing from potential ESPs for power procurement (power supply portfolio plus CAISO schedule coordination) as well as back-office customer service functions prior to filing a CCA implementation plan with the CPUC. The responses would provide the basis for either validating the cost assumptions in this Study or providing a foundation for updating the assumed costs based on the Request for Information responses.

I fully agree. A market-based approach should be used to solicit indicative offers for 1-3 year and 5-7+ year contracts for wind and solar, as well as corresponding amounts of natural gas energy and capacity required to fill in the Tri-County daily load curve, after netting out contracted deliveries of wind and solar. As discussed in the Study, energy required to balance day-ahead and real-time differences between the CCE load and resources will be procured through California Independent System Operator markets. These indicative PPA costs for wind, solar and natural gas energy should then be used to re-run the Monte Carlo simulations shown in Tables 40 and 41 at page II-55, which show 95% confidence interval power procurement costs and sensitivity analyses for the Middle of the Road (50%) renewable energy content portfolio.

Power Cost Indifference Adjustment Charges

In addition, the Study appears to make overly pessimistic estimates for the Power Cost Indifference Adjustment charges that will be allowed by the California Public Utilities Commission (CPUC) for CCEs formed in the Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) service territories. At page II-85, Table 56 shows an IOU Cost Responsibility Surcharge (CRS) charge of $84.9 million in year 2022, which escalates to $125.1 million in year 2030. These charges amount to a $16.85 per MWH surcharge in 2022, and $25.21 per MWH in 2030. At page II-86, the study authors state that "[w]ith respect to the PCIA, PG&E's February 2017 forecast filed with the California PUC was used for both IOUs."

This approach is unreasonable. At a minimum, PG&E's Power Cost Indifference Adjustment should be applied only to PG&E customers within the study region, not to the roughly 71% of customer load located in the SCE territory (see page II-123). Second, PG&E's filed forecast likely reflects its worst-case estimate of stranded costs for owned generating resources and purchased power contracts, particularly the nearly 50% escalation in the CRS between 2022 and 2030. These estimates mirror the fact that PG&E's power supply costs are substantially higher than SCE's - thus the substantially lower estimated PCIA costs for SCE shown on page II-77. Compare Table 51, which shows an SCE Residential PCIA adder of $0.0078 per kWH as of March 1, 2017 (equivalent to $7.80 per MWH), to the corresponding PG&E PCIA for residential customers in Table 50 of $0.292 per kWH, again equivalent to $29.20 per MWH. A load-weighted average of these PCIA adders would reduce the weighted CRS by about $15 per MWH.

It should be noted that SCE relies much more heavily on purchased power contracts versus utility-owned generation than does PG&E, presumably reflecting the retirement of the San Onofre nuclear generating station and divestiture of much of its fossil fuel generation fleet. For these reasons, SCE's PCIA will be affected by factors such as the loss of load obligations to CCP and other CCEs that may form in its service territory, the composition of it resource portfolio (renewables versus gas), as well as market opportunities to lay off such contract purchases in wholesale markets. Thus, while SCE's PCIA may well increase, use of the PG&E forecast assumes an unduly adverse impact on the financial viability of CCP.

Cost of Capital and Opportunities for Investment in Publicly-Owned Generation Resources

Finally, the Study also appear to ignore the long-term competitive advantage of publicly owned enterprises from the use of long term tax exempt debt to finance major capital investments. Over the long term, an increasing share of the CCP power supply portfolio could be comprised of generating projects that are owned by the CCP or by the participating jurisdictions. Publicly-owned utilities typically have a two-to-one or better advantage on cost of capital compared to investor-owned utilities. The higher costs of corporate bonds compared to municipal tax-exempt debt explains part of this difference, but the larger component is the need for investor-owned utilities to finance capital investment through capital structures with debt/equity ratios of about 50% and after-tax equity returns of 8-10%. While project financing of new generation through take-or-pay contracts allows the private sector to reduce capital costs though use of debt leverage and shifting of risks to purchasers, the competitive advantage for public ownership remains. Congress is considering changes to the federal tax code and a variety of enterprise forms such as partnerships can be used to minimize federal tax liabilities; nonetheless, publicly-owned enterprises continue to have a major competitive advantage, subject to tax code provisions outlined below for wind and solar projects.

Under current tax law, investor-owned enterprises can take advantage of a 30% investment tax credit for solar energy and a wind production tax credit based on the energy output of qualifying wind facilities. While these features of the federal tax code currently create a significant competitive advantage for private ownership, the solar PTC is already being phased out over a multi-year period. Moreover, it may be possible for CCP to jointly develop solar projects with a tax equity partner, such that CCP buys out and takes ownership of the project after the ITC and accelerated tax depreciation benefits have been fully utilized by the tax investor. In contrast, the wind PTC generally favors ownership by entities with continuing federal tax liabilities that can be offset. Nonetheless, joint-ownership arrangements for wind facilities may be possible in the future.

Ownership of generation resources should be considered as part of a long term CCE business plan that would reduce power market price risks for the enterprise. Project ownership would also provide a vehicle for CCE development of community solar projects that allow residents and businesses to fully offset their carbon footprints at much lower costs to these customers and society than rooftop solar.

Thank you for the opportunity to provide these comments.