BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 11-05-005 (Filed May 5, 2011)

CLEAN COALITION OPENING COMMENTS ON

ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON

STAFF PROPOSAL ON IMPLEMENTATION OF SENATE BILL 1122

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CLEAN COALITION OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON STAFF PROPOSAL ON IMPLEMENTATION OF SENATE BILL 1122

In accordance with the Assigned Commissioner Ruling released November 19, 2013, the Clean Coalition provides the following opening comments.

The Clean Coalition is a California-based nonprofit organization whose mission is to accelerate the transition to local energy systems through innovative policies and programs that deliver cost-effective renewable energy, strengthen local economies, foster environmental sustainability, and enhance energy security. To achieve this mission, the Clean Coalition promotes proven best practices, including the vigorous expansion of Wholesale Distributed Generation (WDG) connected to the distribution grid and serving local load. The Clean Coalition drives policy innovation to remove major barriers to the procurement, interconnection, and financing of WDG projects and supports complementary Intelligent Grid (IG) market solutions such as demand response, energy storage, forecasting, and communications. The Clean Coalition is active in numerous proceedings before the California Public Utilities Commission and other state and federal agencies throughout the United States in addition to work in the design and implementation of WDG and IG programs for local utilities and governments.

The Clean Coalition urges the Commission to take this opportunity to consider two refinements to the proposed implementation of SB 1122 and existing implementation of SB 32:

1. Allow the bimonthly 5 MW allocation for each product category to be exceeded by up to 1 MW to better accommodate the size of queued projects and avoid unnecessarily delaying projects and program capacity allocation.
2. Request the CPUC implement a method to recognize transmission capacity usage costs to establish differential value to be reflected in a PPA price adjustment.

1. The bimonthly 5 MW allocation should allow up to 1 MW capacity exceedance as needed to avoid delaying procurement

The Clean Coalition recommends that the Commission allow the existing bimonthly allocation to be exceeded by up to 1 MW accommodate the size of the next project in queue and avoid leaving up to 2 MW of each bimonthly allocation unfilled. The vast majority of projects participating in this procurement are either 1.5 MW or 3 MW, as evidenced by the current ReMAT queue and interconnection queue applicants awaiting results for ReMAT eligibility. These project sizes do not readily add up to 5 MW, frequently resulting in only a single 3 MW project being offered a PPA and nearly always resulting in incomplete and inefficient allocation of capacity. For example, if the first one or two projects consume 3 MW of the allocation, only 2 MW remain; if the next project is 3 MW, it cannot be accommodated, leaving the bimonthly allocation 40% underutilized; if the next project is 1.5 MW, 10% of the bimonthly allocation will still remain likely unfilled. Adopting a 6 MW bimonthly allocation, or allowing flexibility in the 5 MW allocation to accommodate the next queued project, will greatly reduce this underutilization and allow two 3 MW projects or two 1.5 MW projects and one 3 MW project in each bimonthly allocation.

Applicants are not able to reduce their project size to match the remaining PPA allocation capacity as this would invalidate their interconnection results, their cost basis, and their efforts to optimally match project design to the site after spending considerable time and money to be eligible to enter the procurement queue. As the Commission must be aware, projects do not have the ability to adjust to a lower than capacity PPA than they are designed for – not only are economies of scale lost, but interconnection applications for Fast Track prevent developers from changing the size of the project. This will require developers to re-apply for interconnection before seeking an SB 32 PPA.

Likewise, the Commission has appropriately taken measures to require interconnection applicants to make financial commitments to proceed with interconnection or withdraw their projects, however such commitments are increasingly risky if allocation of PPA capacity is delayed.

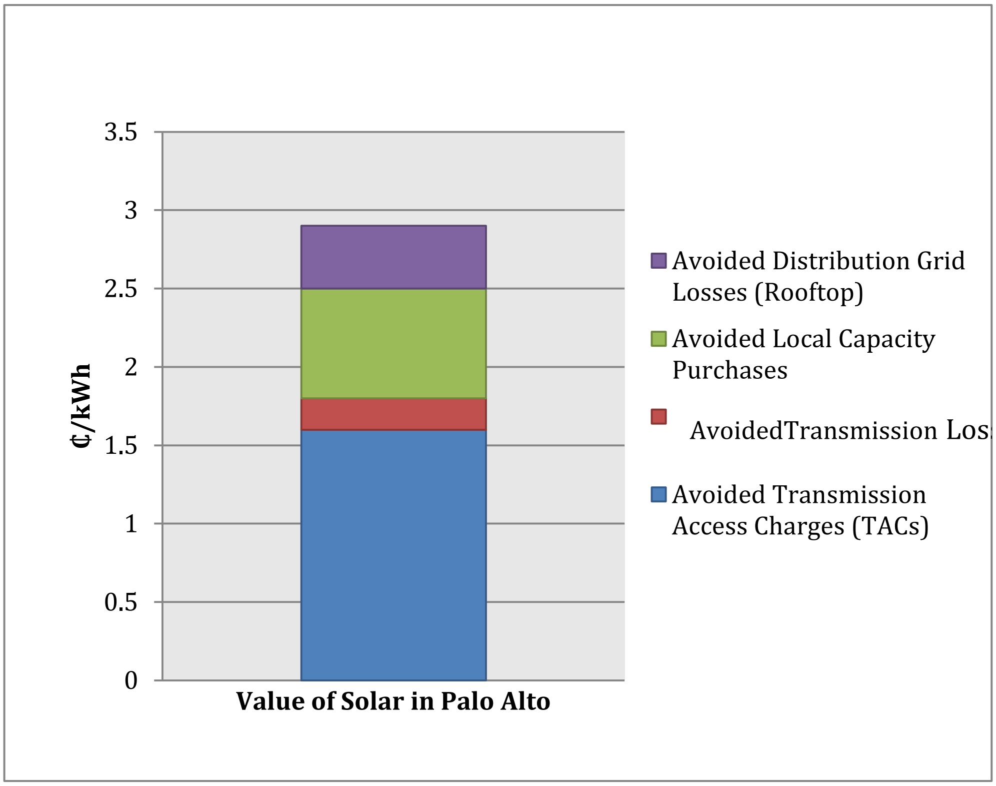
Bimonthly allocations that are incompletely filled, potentially accommodating only a single 3 MW project, may negatively impact ratepayers or market participants by hindering the ability of the price adjustment mechanism to effectively poll the market for the lowest viable price.

The Commission previously agreed with this rationale in expanding the bimonthly capacity from 3 MW to 10 MW (in the PD, pp. 10-11, and APD, pp. 10-11) before the 5 MW allocation was introduced in the final decision. We strongly recommend that the Commission increase bimonthly allocation to 6 MW or allow up to 1 MW of flexibility in the bimonthly allocation to accommodate queued projects without delay.

2. The "strategically located" determination should be supplemented with consideration of locational value in order to improve ratepayer value by focusing on serving local load in accord with Assembly Bill 327.

As noted in D. 13-05-034 at 28, while § 399.20(e) states, in part: "The commission shall consider and may establish a value for an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit." the Commission is not required by this statute to establish a locational value or related price adjustment in this proceeding. Recognizing the potential significance of these values in procurement policy however, the Commission is working toward developing a methodology to value avoided transmission and distribution costs, and has held workshops on this topic. These efforts have not yet resulted in a proposal for implementation by the CPUC, municipal utilities including Austin, Los Angeles, Fort Collins, and Palo Alto have already incorporated these factors in calculating an Avoided Cost value for distribution grid feed-in tariff programs, and the Clean Coalition is currently doing so in for a case study project in San Francisco. The results of these studies show the simplest costs to estimate include the Transmission Access Charges (TACs), line losses, marginal cost and merit order impact associated with the use of transmission capacity which, at 2.4-5.1¢/kWh[1], typically represent the largest avoidable costs associated with location.

Figure. 1. *Palo Alto Utilities avoided cost calculations.*



Since the costs or benefits are realized by ratepayers through long term energy, capacity, and transmission procurement commitments regardless of whether they have been accounted for and even before an accounting methodology has been adopted, it is reasonable and appropriate to apply estimated values in the interim and to incorporate these values in the selection process for resources at the earliest opportunity.

Additional support for the Commission's efforts in this regard are afforded by Assembly Bill (AB) 327, signed in 2013, which requires the investor owned utilities to "submit a distributed resources plan proposal to identify optimal locations for the deployment of distributed resources" by July 1, 2015. In developing these plans, the utilities are

[1] A more detailed example of these values developed for San Francisco can be found in the Executive Summary of the Clean Coalition's Analysis of the Hunters Point Project, available at http://www.clean-coalition.org/site/wp-content/uploads/2013/12/HPP-Impact-Analysis-18_jb-19-Dec-2013.pdf.

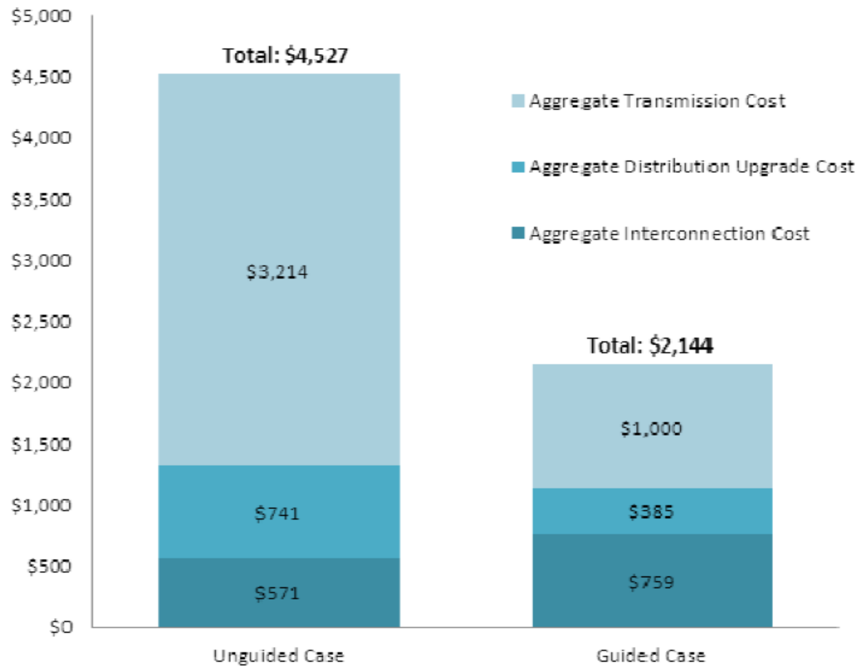
required to "evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation is to be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation."[2]

Southern California Edison has worked with the Energy Commission and the CPUC in evaluating some of the cost differences associated with location, indicating very substantial ratepayer savings where policy recognizes and thereby guides distributed generation to locate close to load. Their study[3] found that integration costs for their share of the Governor's goal of 12,000 MW of distributed generation varied from $2.1 to $4.5 billion, with the lower costs associated with the "guided case" (70 percent of projects located in urban areas), and the higher costs associated with the "unguided case (70 percent projects located in rural areas). The guided case assumes policies or incentives should encourage development of distributed generation mostly in urban areas.

Figure 4: Integration Costs for Distributed Generation

[2] Section 769 of the California Public Utilities Code, as amended by AB 327 (2013)

[3] The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System, SCE, May 2012



Source: Southern California Edison, 2012

76% of national transmission expenditure between now and 2023 are to integrate renewables.[4] In these cases it is not a choice between energy sources, but of energy scale and location. Guided deployment of renewables can substantially decrease these costs, and combined with Intelligent Grid solutions in grid planning, including the application of advanced inverters, storage, and automated demand management at the distribution level, the need for both transmission and additional conventional base load and flexible capacity is further reduced. If future increases in electric demand are met entirely with local generation and locally sourced balancing, major ratepayer savings will be realized. The Alternative Fueled Vehicles proceeding, R. 13-11-007 is intending to plan for the integration of 1.5 million electric vehicles by 2025, representing 35 GW of potential new flexible demand capacity located on the distribution system in existing load centers and ideally served by local generation.

Recommendation:

Ratepayer impacts related to energy costs, line losses, transmission capacity and Transmission Access Charges (TAC) are clearly identifiable and are much more

[4] Tweed, Katherine, "US Transmission Investment will Peak at $14 billion in 2013".

significant to ratepayers than project specific upgrades. The Clean Coalition recommends complementing the current $300,000 transmission system network upgrade cost limit criteria intended to reflect projects that are "sited near load"[5] with the more accurate determination based on whether the project will exceed minimum coincident load (MCL) on the local distribution system.

MCL is easily estimated based on local peak load data which is now published through each regulated utility's online interconnection maps[6], which were developed precisely to assist in siting projects in preferred locations and "right sizing" them to reduce costs and optimize value. Once a likely site is identified based on map derived MCL estimates, hourly SCATA load data can establish MCL with relatively high accuracy very early in the design and study process.

For simplicity we recommend initially establishing a price adjustment at the levelized 20 year TAC rate multiplied by the percentage of output exceeding minimum coincident load.

> For example, if a project's output of 2 MW exceeded MCL not already allocated to other projects by 20%, the PPA would reduce payment by 20% x $24/MWh TAC = $4.8/MWh.

This figure would be fully predicable by applicants prior to their entry into the queue, and prior to any opportunity to respond to a PPA offer at each ReMAT opportunity, while encouraging strategically preferable siting. As the Commission proceeds with further evaluation of locational costs and benefits, more comprehensive adjustment factors can be established.

The Clean Coalition appreciates the opportunity to provide these comments. We urge the Commission to adopt the recommendations herein, and look forward to working with the Commission and other parties to this proceeding.

Respectfully submitted,

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[5] D. 12-05-035 at 61: ...generators must be "strategically located." This means that the generator be (1) interconnected to the distribution system, as opposed to the transmission system, and (2) <u>sited near load</u>...

[6] For example SCE Interconnection Map (prepared for the Renewable Auction Mechanism) http://www.sce.com/EnergyProcurement/renewables/renewable-auction-mechanism.htm

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