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)

REPLY COMMENTS OF THE SOLAR ALLIANCE ON OCTOBER 13, 2011 RENEWABLE FIT STAFF PROPOSAL

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In accordance with the October 13, 2011 Administrative Law Judge Ruling (1) Issuing Staff Proposal, (2) Entering Staff Proposal and other Documents into the Record, and (3) Setting Comment Dates, the Solar Alliance [1] replies to certain comments of other parties on elements of the Staff proposal for the implementation of Senate Bill (SB) 32 and related SB 2 1X amendments to Public Utilities Code Section 399.20 filed in the above captioned proceeding on November 2, 2011.

I. INTRODUCTION

The number of comments submitted on the Staff's proposal by various factions of the renewables industry and the detailed nature of those comments indicates extreme interest in the SB 32 program, as well as a desire to quickly implement the statutory program enacted almost three years ago. In contrast, the three investor-owned utilities (IOUs) present comments which are intent on throwing up all sorts of road blocks to successful Commission implementation of a statutorily mandated program. If the IOUs were to have their way, the Commission would adopt a program which would provide SB 32 generators minimal compensation, thus rendering such

[1] The comments contained in this filing represent the position of the Solar Alliance as an organization, but not necessarily the views of any particular member with respect to any issue.

projects unfinanceable. In its comments below, the Solar Alliance focuses on a few elements of the IOUs' comments which illustrate what appears to be the IOUs overall strategy and the deficiencies therein. In particular, the Solar Alliance will respond at length to the IOUs' criticisms of the innovative efforts of the Staff and its consultant E3 to develop a methodology for using the IOUs' distribution plans to value the distribution costs that will be avoided by SB 32 projects.

II. STAFF'S PRICING PROPOSAL REFLECTS MARKET PRICING

The IOUs' fault the base price utilized under Staff's Proposal -- i.e., the market clearing price from the RAM auction-- as being an administratively set price not reflective of the IOUs' avoided costs. [2] Furthermore, the IOUs' argue that "one of the primary defects of administratively-determined pricing is that it is not based on market pricing, but rather guesses at what such prices will be."[3] Therefore, they assert, that "as a result, administratively-determined prices are almost always too high or too low." The IOUs' criticism of the Staff proposal is unfounded.

The Staff proposal starts with an initial FIT price based on the RAM market clearing price given the determination that" RAM represents the most relevant renewable market segment that the Renewable FIT generators are avoiding."[4] However that price is not fixed, but as recognized by Staff, would be adjusted based on "market response" to the program. In basic terms, the price would be adjusted up or down depending on response to the program. These

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2 San Diego Gas & Electric Company (U 902 E) Comments in Response to Ruling dated October 13, 2011, R. 11-05-005 (November 2, 2011) (SDG&E Comments), at p.6.; Southern California Edison Company's Comments on the October 13,2011 Renewable FIT Staff Proposal and other Attachments , R. 11-05-005 (November 2, 2011) (SCE Comments) at p.8.

3 SCE Comments at p. 10.

4 Staff Proposal at p. 9.

adjustments would be aimed at reaching the market clearing price for FIT projects. This is not an administratively set price, but one geared to capturing the true market price of such projects.

Moreover, while SCE attacks the Staff's pricing proposal as one being administratively set, it is hard to discern the substantive differences between what Staff is proposing and what SCE itself has advanced as a market based approach. Thus, SCE states that:

> SCE's proposal is a straightforward and effective method for avoiding the problem of administratively-set prices that are too high or too low. SCE would simply start with an initial FiT price and offer a portion of the overall program capacity each month. *The price would increase if there is no program subscription, decrease if there is full program subscription, or remain the same if there is partial subscription. This market-based pricing methodology allows the renewable FiT price to constantly adjust to the market without the need for guesses regarding the prices the market will bear.*[5]

The Staff's proposal is following the same basic principles and the same basic price adjustment mechanism as SCE's proposal. The IOUs' arguments that the Staff proposal should be rejected as an administratively set price should themselves be rejected.

III. TRANSMISSION AND LOCATIONAL ADDERS ARE WARRANTED

The Staff pricing proposal provides, in certain circumstances, for both a transmission adder and a locational adder. The IOUs raise numerous objections to these adders, asserting that they are unwarranted, flawed, and, at minimum, would require hearings prior to implementing. As illustrated below, the IOUs' arguments are unfounded, and ignore numerous and policy and factual reasons which support the adoption of such adders.

A. Transmission Adder

All three IOUs object to the element of the Staff's proposal which provides that, in addition to the market clearing price established in the RAM auction, the transmission costs "attributed" to the RAM project establishing the market clearing price should be included in the

[5] SCE Comments at p. 3.

FIT base price. While PG&E[6] and SDG&E[7] argue that including such costs is duplicative as they are already recognized through either their inclusion in the locational adder or by virtue of being embedded in the project costs used to formulate the RAM bid (which ultimately becomes the RAM clearing price), SCE's argument is more focused on whether there is sufficient evidence that the transmission costs for the market clearing RAM projects are representative of the IOUs' avoided costs.[8]

The IOUs' arguments ignore one of the fundamental purposes for developing small-scale, widely distributed generation projects – to avoid the need for the transmission investments required to access and interconnect large-scale, central generation projects. SB 32 projects are small, will be located on the distribution system, and will allow the utility to avoid transmission costs because their power will serve local loads on the distribution system. Indeed, the authorizing statute defines SB 32 projects as those which are "strategically located and interconnected to the electrical transmission and distribution grid in a manner that optimizes the deliverability of electricity generated at the facility to load centers."[9] Accordingly, what these projects will avoid is the prevailing market-clearing price for the *combination* of a transmission-level renewable project (such as a RAM project) and the associated costs of the transmission upgrades required to serve it. This market-clearing RAM project could be a more costly generation project with low transmission costs, or a lower-cost generator with more expensive transmission interconnection and upgrade costs. What is important is that the combination of the

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6 Pacific Gas and Electric Company's Comments on Staff's Proposal Regarding the Implementation of Section 399.20, R. 11-05-005 (November 2, 2011) (PG&E Comments) at p.8.

7 SDG&E Comments at p.9.

8 SCE Comments at p. 13.

9 P.U. Code Section 399.20(b)(3).

RAM project's generation and transmission costs represents the utility's avoided, market-clearing costs for smaller renewable generation that is sited to avoid transmission costs.

The IOUs try to assert that it would be duplicative to pay SB 32 generators for transmission costs which the utilities will not incur. In fact, that is precisely why it is completely appropriate (and legal) to include transmission costs in the SB 32 price – these are costs that these small generators will allow the utility to avoid. SCE, in particular, consistently has urged the Commission to use market pricing for new renewables. The Solar Alliance is thus surprised that SCE is opposing what appears to be the Staff's well-considered proposal for a market-based starting price for the product that SB 32 projects will provide – small renewable generation that avoids both generation and transmission costs for the IOUs.

B. Locational Adder

All three IOUs object to Staff's locational adder even more vociferously than to the transmission adder. Their arguments range from the absence of a sufficient showing that FIT projects will actually allow the IOUs to avoid any distribution costs (thus failing the avoided cost test under PURPA) to particular criticisms of the E3 study relied upon by Staff as a means to calculate the locational adder. Upon closer review, the IOUs' arguments are revealed for what they truly are -- an unjustified attempt to ignore (and therefore to not compensate the generator for) the benefits which DG provides to the distribution system.

1. The IOUs have Failed to Effectuate State Law Pursuant to P.U. Code Section 353.5 or Commission Policy Established in Decision 03-02-068.

PG&E raises the threshold argument that current Commission policy, as stated in D. 03-02-068 and D. 09-08-026, requires that distributed generation projects meet certain criteria for being installed in the right place at the right time, if such projects are to receive actual payments for avoided distribution costs. PG&E accepts that the Commission has not required that such criteria be met for avoided transmission and distribution costs to be included in program evaluations for energy efficiency and distributed generation, but argues that such criteria must be met if adders based on avoided distribution costs are to be paid to SB 32 projects. PG&E's argument is further evidence that the utilities have failed to implement properly the criteria adopted in D. 03-02-068.

During the 2000 – 2001 California energy crisis, the Legislature enacted SB 28, which was intended in part to encourage the installation of DG resources. This legislation included the addition of Public Utilities Code Section 353.5, which provides as follows:

> 353.5. Each electrical corporation, as part of its distribution planning process, shall consider nonutility owned distributed energy resources as a possible alternative to investments in its distribution system in order to ensure reliable electric service at the lowest possible cost.

The Commission sought to implement this law in Rulemaking 99-10-025. D. 03-02-068 was the final order in that rulemaking. The criteria set forth in D. 03-02-068 were designed as part of a set of policies to implement this law and thus to encourage the utilities to consider DG as an alternative to distribution upgrades. Notwithstanding this state law, the Solar Alliance is not aware of any DG project since 2003 that has been able to qualify for payments for avoided distribution costs pursuant to D. 03-02-068, even though that decision required the utilities to incorporate DG into their distribution planning and to make outreach efforts and to conduct RFOs seeking DG projects that could defer distribution upgrade.[10] One utility, SCE, admitted in discovery in its pending rate case that it has never made a distribution deferral payment to a DG project under the criteria in D. 03-02-068, and has agreed in a settlement in that case to improve

[10] D. 03-02-068, at 15-20 and 62-69.

its procedures for incorporating DG into its distribution planning process.[11] Far from promoting DG, the IOUs' have used the criteria in D. 03-02-068 as an effective barrier to DG development. The Solar Alliance believes that the E3 locational adder methodology presented in this case represents a groundbreaking effort to develop a much more workable approach to implementing the "right place, right time" criteria of D. 03-02-068 in a way that will more effectively incorporate DG development into the utilities' distribution planning consistent with the longstanding requirements of P.U. Code Section 353.5.

2. Failure to Recognize the Benefits of DG will Result in Overbuilding of the Distribution System.

The IOUs' comments on the locational adder show that they want to continue to keep any consideration of distributed generation out of distribution planning. They advance a number of arguments about why the E3 locational adder for SB 32 projects may not actually result in avoided distribution costs: they claim that either too little or too much distributed generation will be installed, the time frame for distributed generation projects does not fit with the time frame for distribution planning, or that distributed generation technologies do not provide adequate capacity or "operational flexibility" to defer distribution upgrades.[12] As a result, the utilities argue that ratepayers may end up both paying a locational adder to a distributed generation project and paying for a distribution upgrade which that project was unable to defer. What the IOUs do not recognize, however, is that excess ratepayer costs also will result if the utility position is adopted, if no effort is made to recognize that distributed generation can avoid distribution costs, and if no workable process is developed to combine distributed generation

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[11] *See* Prepared Direct Testimony of R. Thomas Beach on behalf of the Cite to Vote Solar Initiative (VSI), served June 1, 2011 in A. 10-11-015, at 21-23 and Attachment RTB-3. *See also,* the SCE and VSI Joint Motion for Approval of Settlement, filed in A. 10-11-015 on September 2, 2011.

[12] *See e.g.,* PG&E Comments, at 15-17

development with distribution planning. In the IOUs' preferred world, they will continue to plan distribution upgrades without considering distributed generation. However, given the clear direction in state energy policies, distributed generation will be built that will reduce distribution loadings and that could have reduced distribution upgrade costs if that distributed generation had been reflected in the IOUs' plans. The result in this scenario is also an overbuilt system and excessive long-term ratepayer costs.

3. IOU Arguments that DG will not Result in Avoided Distribution Costs do not Withstand Scrutiny.

The Commission should examine closely each of the IOU arguments that the location adder will not result in avoided distribution costs, or will overstate those costs. Many of these arguments can be turned around to argue equally plausibly that a locational adder will understate avoided distribution costs. For example, PG&E argues that it might declare a "hot spot" for distributed generation development based on a certain assumed load growth which may not materialize, and thus it would overpay distributed generation in that area.[13] But the converse also can occur – load growth in that area could exceed expectations, and the distributed generation projects in that location could defer more capacity needs than anticipated, at a lower cost than if all of the distribution upgrades had been built. Similarly, PG&E tries to argue that ratepayers will overpay if a "hot spot" is oversubscribed with distributed generation.[14] Yet again the converse also could occur – for example, a locational adder that is based on a five-year deferral of an upgrade could attract enough distributed generation such that the upgrade could be pushed back for ten years, resulting in additional deferral benefits for ratepayers for the costs of a

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[13] PG&E Comments at p. 16.

[14] *Id.*

much shorter deferral.[15] The IOUs already must undertake distribution planning with significant uncertainties related to load growth, economic activity, and constraints in land use and environmental impacts. While incorporating distributed generation into distribution planning does introduce a new variable, distributed generation also provides a new tool with which distribution needs can be met and distribution costs avoided, and the uncertainty associated with this new element can be minimized if the locational adder is based on actual utility distribution plans, as E3 has proposed.

4. DG can Produce Reliable Savings in Distribution Capacity.

The IOUs' opening comments argue, in various ways and to varying degrees, that distributed generation cannot produce reliable savings in distribution capacity that will allow distribution upgrades to be avoided. For example, SCE asserts, without citation, that the E3 study assumes that PV systems will deliver their full capacity during peak periods.[16] Yet E3's presentation clearly states that E3 used the simulated profile of PV output to calculate avoided costs. Such a profile obviously includes the impact of PV intermittency.[17] SCE's comments also distort the findings of the *CSI 2010 Impact Evaluation Report.* SCE claims that page 6-13 of this report shows that fixed PV arrays produce only "a paltry 15% of capacity" in CAISO peak hours.[18] The report actually shows that fixed arrays produce about 33% of their rated capacity over the critical top 100 load hours. West-facing fixed arrays and tracking systems perform even

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15 PG&E attempts to argue that a distribution upgrade which is deferred for a period of years, but not eliminated, does not represent an avoided cost. This is incorrect: a deferral of an upgrade provides ratepayers with a near-term cost that they avoid, for the period of years that the upgrade is delayed, even if that avoided cost is not as large as it would be if the upgrade were permanently eliminated. PG&E Comments, at 11. T his is illustrated in Attachment C, Slides 16-20 of the E3 presentation

16 SCE Comments at p. 16.

17 Attachment C, Slide 12.

18 SCE Comments at p. 16.

better, producing 52% and 63% of their rated capacity, respectively in the top 100 hours when reliability is most important. SCE's "paltry 15%" is the output of fixed arrays over the top 1,000 load hours on the CAISO system, which is well beyond what is typically considered to be the critical peak load hours.[19] The Commission has adopted a method for evaluating the capacity value of intermittent resources for resource adequacy purposes, in other words, to evaluating the contribution of such resources to meeting system peaks.[20] The Commission clearly could use or adapt that approach to valuing the ability of intermittent distributed generation resources to avoid distribution peaks.

5. Distribution Cost Are Avoided Even in "Not-Hot" Locations.

The E3 approach develops locational adders both inside and outside of "hot spot" locations. PG&E argues that the locational adders outside of "hot spot" locations should be zero. This fundamentally misunderstands the E3 proposal. As shown in E3's Slide 26, the "hot spots" are determined by selecting locations covering 5% or 10% of each utility's loads where the potential avoided distribution costs are the highest. Obviously, this does not mean that avoided distribution costs in the "not hot" areas are zero. Avoided distribution costs of zero imply that a distributed generation project in that location will never allow the utility to reduce its distribution costs. This is highly unlikely, given the 20-25 year useful lives of such projects. Even if a utility's 5- to 10-year distribution plan does not show avoided distribution costs at a particular

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19 PV output drops off as the number of top load hours is increased, because an increasing number of the top load hours will be in the later hours of summer afternoons and evenings when PV output is dropping off as the sun sets. However, demands in these additional hours are much lower than in the critical top 100 load hours. For example, in 2010 the CAISO system load in the peak hour was 47,282 MW; in the 100th top load hour it was 42,367 MW, just 10% lower. In contrast, in the 1,000th top load hour, demand was only 31,486 MW, 33% below the peak hour.

20 *See* D. 09-06-028, at pp.46-54 and Appendix C (adopting the 70% exceedance method to value the capacity of intermittent resource).

location, such costs can materialize at some point over the full life of a distributed generation investment.

6. Further Review of the E3 Methodology

The Solar Alliance recognizes that there are outstanding questions about the E3 methodology for calculating a locational adder, as well as further details that need to be resolved about how the E3 approach can best be integrated with utility distribution planning efforts. The Solar Alliance recommends that the Commission ask E3 to provide further details on its proposal, and schedule a further workshop at which questions on the E3 proposal can be addressed and the parties can discuss ways in which distributed generation development and distribution planning can be more effectively integrated through locational pricing for distributed generation.

IV. STATUTORY LANGUAGE MUST BE IMPLEMENTED IN A MANNER WHICH DOES NOT PROHIBIT A SUCCESSFUL PROGRAM

Given the protracted time required and the potential exorbitant costs, the Staff's proposal rejects the idea that all FIT generators must be deliverable in order to participate in the SB 32 program. In response, the IOUs argue that given the language of Public Utilities Code Section 399.20(i), which states that "the physical generating capacity of an electric generation facility shall count toward the electrical corporation's resource adequacy requirement", the Commission cannot simply ignore the necessary prerequisites for SB 32 generation to count towards an IOU's RA requirement. While SCE takes the most hard-line position, insisting that all SB 32 projects should be required to undergo deliverability studies and complete all required upgrades, the other two IOUs recognize that there are other options which could be pursued to allow compliance with Section 399.20. The Solar Alliance agrees with PG&E and SDG&E that these other options can be pursued, and supports these IOUs in their efforts to find a reasoned solution. In assessing these options, however, the Commission must determine whether the option itself would be counterproductive, creating a financial barrier to participation in the SB 32 program.

SDG&E, like the Solar Alliance in its opening comments, noted that interplay between RA requirements and RPS procurement, including FIT programs, is currently being vetted in other forums. Accordingly, again like the Solar Alliance, SDG&E recommended that in the interim the Commission "follow the guidelines established in the RAM program regarding deliverability studies and RA." Specifically SDG&E states that it:

> "will sign a contract with a developer that has not yet attained a deliverability study, and then require that they do so through the next available CAISO cluster study window. The cost for such a study is relatively low and the project would only have to achieve Full Capacity Deliverability Status (as defined in the CAISO tariff) if such status could be achieved with no additional cost to Seller."[21]

The Solar Alliance continues to believe that such is the most pragmatic approach, allowing the program to move forward without delay.

PG&E, however, offers three additional options for Commission consideration. First, the Commission could reduce the IOU's RA obligation by an amount equivalent to the capacity delivered by the SB 32 generator which is not RA compliant. The Solar Alliance supports such an option because, by reducing the IOU's RA obligation, this adjustment renders the transaction fully compliant with the statutory language that the generating capacity of the SB 32 generator count towards the IOU's RA requirement.

PG&E's second and third recommended options pertain to modifying the overall price received by the FIT generator to reflect the fact that the SB 32 generator is not providing RA value. Neither of these two options – first, a determined reduction in the price, to be eliminated once the Commission addresses the RA counting issue either through the RA OIR or another proceeding, or, second, the use of energy-only TOD factors to reflect the fact that a FIT project is

21 SDG&E Comments at p. 18.

not providing RA -- is workable. Merely because the RA rules have not been adopted that allow this capacity to be counted for RA purposes does not mean that this generator is not providing a capacity product. Similar intermittent generators provided capacity products, and were compensated for those products, before the RA program was implemented in the mid-2000s. Accordingly, the price and/or the TOD factors should reflect such capacity value. Moreover, the elimination of the capacity component of the price or of the TOD factor would place the commercial viability of a vast majority of SB 32 generators at risk. Recognition of the capacity resource which certain of these generators provide to the grid during peak periods forms the basis of their compensation which renders them commercially feasible. Absent such recognition and appropriate compensation, the ability to develop a financeable project is significantly compromised, negating the purpose of the legislation.

Respectfully submitted this November 14, 2011 at San Francisco, California.

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By *\/s/ Jeanne B. Armstrong*
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VERIFICATION

I am the attorney for the Solar Alliance in this matter. Solar Alliance is absent from the City and County of San Francisco, where my office is located, and under Rule 1.11(d) of the Commission's Rules of Practice and Procedure, I am submitting this verification on behalf of the Solar Alliance for that reason. I have read the attached "Reply Comments of the Solar Alliance on October 13, 2011 Renewable FIT Staff Proposal." I am informed and believe, and on that ground allege, that the matters stated in this document are true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 14th day of November, 2011, at San Francisco, California.

/s/ Jeanne B. Armstrong
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