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)

THE SOLAR ALLIANCE'S REPLY COMMENTS TO SECTION 399.20 RULING DATED JUNE 27, 2011

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In accordance with the June 27, 2011 Administrative Law Judge's Ruling Setting Forth Implementation Proposal for Senate Bill (SB) 32 and SB 2 1X Amendment to Section 399.20 (June 27 Ruling), the Solar Alliance[1] replies to certain comments submitted by parties on the implementation of each statutory element of SB 32.

I. INTRODUCTION

Implementing new Public Utilities Code Section 399.20 – i.e., expanding the prior feed-in tariff provisions for RPS-eligible generation – was set as one of the high priority issues in this new rulemaking proceeding which, among other things, is aimed at making the necessary RPS program changes so as to ensure reaching the new statutory procurement target of 33% of retail sales by 2020. The high priority ranking is reflective of two facts - first that, as intended by the legislature, a successful SB 32 program can help the state reach its renewable goals and, second, that SB 32 was enacted almost two years ago and it has yet to be implemented. Review of the opening comments shows that positions taken by certain parties in two areas – pricing and interconnection – if adopted by the Commission would serve to unnecessarily (on both a legal and technical basis) protract implementation of this statute for another year or two or more; further thwarting the legislature's intent in its enactment and continuing current market

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.

uncertainty as to the viability of small scale renewable projects.

II. IN ORDER TO ACHIEVE A 2011 DECISION ON THE IMPLEMENTATION OF SB 32, THE COMMISSION SHOULD ADOPT MPR PRICING AND WDAT INTERCONNECTION PROCEDURES ON AN INTERIM BASIS.

A. Pricing Issue

Review of the opening comments on pricing issues shows that parties are essentially in three camps – use of the market price referent (with or without adders);[2] use of technology based rates;[3] and use of market based rates.[4] While the use of technology or market based rates could be promising, these pricing alternatives, unlike the MPR, could result in significantly protracting the already delayed implementation of the SB 32 program for at minimum another year, and perhaps longer. While those who support use of technology or market based rates do not directly reference this significant drawback, such is made evident by the presentation of their respective proposals.

Thus, for example, Sustainable Conservation and GPI, in supporting technology specific rates, point to a October 2009 CEC study, *Economic Study of Bioenergy Production from Digesters at California Dairies* and a May 2011 study by the State Water Board, titled *Economic Feasibility of Dairy Manure Digesters and Co-Digestion Facilities in the Central Valley of California* as support for the proposition that bio-energy projects need a rate in a 28-30

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2 For example, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), The Utility Reform Network / Coalition of California Utility Employees (TURN /CUE), and the Solar Alliance.

3 For example, Sustainable Conservation, Agricultural Energy Consumers Association (AECA), Center for Energy Efficiency and Renewable Technology (CEERT) , FuelCell Energy, Inc. (FuelCell), and the California Solar Energy Industry Association (CalSEIA)

4 For example, Southern California Edison Company (SCE), Interstate Renewable Energy Council (IREC), and the Vote Solar Initiative.

cent range.[5] Moreover, Sustainable Conservation and GPI state that they continue to work with project developers to develop a more robust pricing model.[6] Similarly, AECA supports a base market price for all types of SB 32 projects using a rolling average of the IOUs' costs of procurement from small renewable generators in the previous three years, but then adjusting such base price for individual technologies.[7] AECA points to three sources of data that could be utilized to develop values for the characteristics and benefits, environmental costs, and start-up costs of biogas facilities.[8] Moreover, while AECA has presented a basis for developing the necessary adjustment to the base rate for biogas facilities, it has not done so for all other potential technologies, each of which would also have to undergo the same process to develop the necessary adjustments to the base rate. Finally, FuelCell Energy, in supporting separate technology specific prices for reach type of eligible renewable resource, contends that each renewable resource has a different "value position" with respect to environment, location and product provided which must be individually determined.[9] In this regard, FuelCell Energy points to a study issued by the National Fuel Cell Research Center at the University of California-Irvine, as the best source to use to calculate the value proposition of fuel cells.[10]

While each of these parties provide a starting point for the development of technology specific prices, their proposals are not complete. Even once the proposals are

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5 Sustainable Conservation and Green Power Institute Comments to Section 399.20 Ruling July 27, 2011 (R. 11-5-005) (July 21, 2011) (Sustainable Conservation / GPI Comments) at pp. 6 -7.

6 Sustainable Conservation / GPI Comments at p. 7.

7 Agricultural Energy Consumers Association Comments to Section 399.20 Ruling (June 27, 2011), R. 11-05-005 (July 21, 2011) (AECA Comments) at p. 6.

8 *Id.* at p. 7.

9 FuelCell Energy Inc Comments to Section 399.20 Ruling og June 27, 2011, R. 11-05-005 (July 21, 2011) (FuelCell Comments) at pp. 5-6.

10 *Id.* at pp. 7-8.

finalized, and pricing models presented, the Commission will be faced with a process not unlike the development of the MPR. The Commission is well aware that since 2004 it has conducted significant proceedings and has issued numerous orders refining and updating the MPR model for the levelized costs of a gas-fired combined-cycle plant. There is no reason to think that developing technology specific rates– particularly for technologies that are much less widespread than gas-fired combined-cycles –will not be just as (if not more) contentious.[11]

Similarly those who support a market based rate – namely basing the SB 32 price on the pricing achieved through the Renewable Auction Mechanism- have presented proposals that could take a year or more to implement. For example, IREC has proposed that SB 32 pricing be based on an average of accepted bids in the RAM Program.[12] However, adjustments will need to be made to reflect differences in the market price of electricity for awarded projects of less than 3 MW and projects up to 20 MW to reflect their differing economies of scale.[13] Thus, for the IREC proposal to work, not only would the SB 32 projects have to await the results of the first RAM auction and then determine what adjustments will need to be made to those prices – after the Commission's approval process, they would also be based on projects which may not come to fruition (if awarded at prices too low for successful completion). Again, all this occurs while the SB 32 program gets further delayed.

Finally, SCE has proposed a novel market-based approach to SB 32 pricing which

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[11] *See* The Solar Alliance Comments to Section 399.20 Ruling Dated June 27, 2011, R. 11-05-005 (July 21, 2011) (Solar Alliance Comments), at pp. 7-8; *See also* Pacific Gas & Electric Company's Comments on Section 399.20 Ruling Dated June 27, 2011, R. 11-05-005 (July 21, 2011) (PG&E Comments) at p. ("none of these parties' pricing proposals have been the subject of evidentiary hearings to test the validity of the assumptions and the methodologies, nor has there been any cross-examination of witnesses supporting these proposals.)

[12] Interstate Renewable Energy Council Comments to Section 399.20 Ruling June 27, 2011, R. 11-5-005 (July 21, 2011) (IREC Comments) at p. 9.

[13] *Id.* at p. 10.

would begin with SCE offering a base price for new SB 32 contracts that is the sum of the average CAISO market price over the past year plus an administrative adder for renewable attributes based on a Department of Energy survey of renewable premiums used by utilities in the western United States. SCE then would increase this price by $2 per MWh in every month in which SCE failed to receive an offer to sign a SB 32 contract at that price, or decrease the price by $2 per MWh if it has met its goal for SB 32 contracts. Although this approach is innovative, it has a number of obvious defects that render it ill-equipped for immediate implementation.

First, SCE's base price is very low: the Solar Alliance calculates that it is presently just $49 per MWh.[14] Thus the Solar Alliance strongly doubts that SCE will receive a significant quantity of offers under this pricing regime, particularly for new renewable projects. Indeed, it would appear that until the SB 32 price exceeds about $78 per MWh, which is about 75% of the 2009 MPR for a twenty-year contract beginning in 2012 ($105 per MWh), activity under SCE's proposed pricing regime would be virtually non-existent. Such assumption is supported by the fact that the CEC's 2009 levelized cost of generation for new *large-scale* renewable technologies exceeded $78 per MWh (in 2009 $) for all technologies except wind projects;[15] undoubtedly, the cost for small-scale projects will be higher. In this regard, SCE's own levelized cost for new large-scale wind projects, presented to the CEC in a *2011 IEPR* workshop earlier this summer, was $76 per MWh, without any firming or integration costs.[16]

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14 The SP-15 CAISO EZ Gen market price from August 2010 through July 2011 was $31 per MWh; the DoE survey price for renewable attributes averages $18 per MWh, as cited in D. 11-06-016, at 15.

15 See "Comparative Costs of California Central Station Electricity Generation: Final Staff Report" (January 2010, CEC Publication CEC-200-2009-07SF), at Table 1.

16 SCE May 16, 2011Presentation to *2011 IEPR* Workshop, "CEC Comparative Cost of Generation Model: Analysis of Results and Recommended Model Changes," at 10. Available at http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-16_workshop/presentations/.

Even if the SCE's SB 32 price increases by $2 per MWh every month as contemplated under its proposal, it would take 15 months for the price to rise to $79 per MWh. Further, if SB 32 contracts are not limited to new generation as the Solar Alliance has recommended, a few low-cost projects (such as existing small renewable QF projects that seek a new contract), or a developer who bids his projects too low to be viable, could result in an even lengthier period until the SCE price reaches a level that will attract a significant number of offers. The Solar Alliance is very concerned that SCE's methodology will pressure renewable developers to under-bid projects in order to obtain a contract, particularly as SCE approaches its Cumulative Procurement Target. This could result in many non-viable contracts.

New technology-or market-based methodologies for setting the price for electricity sold from SB 32 generators are certain to engender delays from significant controversy. In contrast, MPR methodology is well-established through a long line of Commission decisions and resolutions. As stated by PG&E:

> [T]he pricing proposals made by other parties have not been litigated and evidence supporting these proposals is generally only referenced in these parties' briefs. None of these parties' pricing proposals have been the subject of evidentiary hearings to test the validity of the assumptions and the methodologies, nor has there been any cross-examination of witnesses supporting these proposals. Because customers will be required to pay for Section 399.20 form contracts for as long as twenty years, the Commission should not adopt a pricing proposal based solely on representations in a party's briefs without specific evidence that has been reviewed and scrutinized in the regulatory process. Before any new pricing proposal is adopted, especially one that may result in significant customer costs over the next two decades, the Commission should first provide sufficient opportunity for the development of an evidentiary record through testimony and hearings. On the other hand, because the MPR methodology has already been the subject of an extensive regulatory process, it can be adopted by the Commission now for purposes of the Section 399.20 Program.[17]

Moreover, it is important to remember that the Commission has recognized that

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17 PG&E Comments at pp. 4-5.

the MPR is an appropriate measure of the IOUs' long-run avoided costs,[18] thus falling within the state's limited jurisdiction to set wholesale power prices for qualifying facilities under PURPA.[19] While SCE argues to the contrary, stating that the MPR "has no relation to the cost of purchasing renewable power, and has nothing to do with the cost a utility avoids through the purchase of power from [a SB 32 Generator],"[20] SCE is wrong.

FERC recently issued an opinion which interprets PURPA as allowing a state to limit the sources considered in setting an avoided cost price pursuant to PURPA. Thus, in addressing the issue FERC correctly posed the fundamental question in determining at what level to set an avoided cost rate –"*what costs the electric utility is avoiding.*"[21] Specifically FERC stated:

> Because avoided cost rates are defined in terms of costs that an electric utility avoids by purchasing capacity from a QF, and because a *state* may determine what particular capacity is being avoided, the state may rely on the cost of such avoided capacity to determine the avoided cost rate. Thus, the avoided cost rate may take into account the *cost of electric energy from the generators being avoided, e.g.*, generators with certain characteristics.[22]

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18 *See* D. 10-04-055, at pp. 5-9. This decision modified and clarified D.09-12-042, the Commission's decision adopting prices to be paid to new small combined heat and power (CHP) facilities developed under AB 1613. These orders adopted a price based on the MPR, recognizing that small CHP facilities allowed the utilities to avoid the costs associated with a new combined cycle plant, which is the basis for the MPR. In doing so, the Commission distinguished this long run avoided cost price from the short-run avoided cost prices that the Commission adopted in D. 07-09-040 for QFs.

19 SCE argues (comments at p.6) that SB 32 does not require a generator to be a qualifying facility thus precluding the Commission from utilizing its ratemaking authority under PURPA. This is incorrect. The Commission is charged with the implementation of SB 32. As part of this statutorily-assigned task it can require any generator who wishes to sell energy to the IOU under an SB 32 contract or tariff to be certified as a QF. Because renewable generators eligible under SB 32 generally will fit the definition of a small power producer QF, they will readily overcome this purported hurdle

20 Southern California Edison Company's Comments to Section 399.20 Ruling Dated June 27, 2011, R. 11-05-005 (July 21, 2011) (SCE Comments) at p. 7.

21 Order Denying Rehearing, 134 FERC ¶ 61,044 at p. 18.

22 Order Denying Rehearing at p. 15.

In this case, the generators being avoided *are not* SB 32 generators but generation from other renewable resources. The MPR represents the cost of alternative sources of generation that are *avoided* by new contracts for renewable generation from SB 32 generators. The MPR is the key pricing benchmark for RPS power, and includes the costs to provide the key renewable attributes of full mitigation of the emissions of greenhouse gases and the offset of criteria pollutants. These are the costs of environmental regulation which the electric corporation avoids through the purchase of renewable energy from the SB 32 generator. The Commission is not legally precluded from basing the price for SB 32 contracts on the MPR.[23]

Accordingly, as recommended by the Solar Alliance in its opening comments, given that use of the MPR provides an expedient means for implementing SB 32, the Commission should proceed with implementation on that basis, but direct that the pricing mechanisms proposed by other parties be re-evaluated at the time the Commission determines a new cost containment mechanism for the RPS – an issue which is to be addressed in this proceeding in 2012.

B. Interconnection

Several parties, noting that interconnection has been a significant barrier to deployment, request that the Commission not wait to address this issue in 2012 but do so immediately.[24] In this regard, parties note that in many cases, it takes a minimum of 2 years to achieve interconnect and such achievement comes at a high financial cost to the generator. The

[23] DRA (comments at pp. 8-9) has recommended use of the net surplus compensation rate which was approved by the commission in D. 11-06-016 as the appropriate pricing mechanism under SB 32. DRA's suggestion should be rejected out right. The basic price under the NSCR is calculated by averaging the CAISO's default load aggregation point price for the IOU during the hours the facilities will most likely be generating. While there might be rationale for such a rate for facilities only selling excess power to the IOU, such is not the case for SB 32 generators selling their entire out put to the IOU.

[24] *See* Sustainable Conservation / GPI Comments at p.15; AECA Comment at pp.14-15; CEERT Comments at 14-15.

Solar Alliance agrees with these parties that interconnection reform is necessary and should be given due consideration by the Commission on a designated time table. However, even a cursory review of parties' comments indicates that such process may not be able to be completed in the mere four months remaining in 2011. Thus, for example, CEERT asserts that interconnection reform necessitates exploring opportunities for the grid operator to have visibility of the resource being interconnected, (i.e. real time generation data) and to be able to disconnect the resource should reliability issues arise,[25] while IREC proposes that California move immediately to a penetration-based screening approach that uses minimum load instead of peak load as a basis for screening interconnection applications.[26] Exploring such proposals take time.

That said, the Solar Alliance is optimistic regarding the current process to undertake modifications to Rule 21, announced by the Commission on August 19, 2011, which aims to achieve an all party settlement and to file such document with the Commission by the end of the year. However, even *if* such lofty goal is met, the Commission's procedures for processing a settlement (even if it is not contested) take several months. Thus, the second quarter of 2012 would be the earliest in which newly approved interconnections protocols could be implemented. The commencement of the SB 32 program should not await resolution of the deficiencies in Rule 21 which would render the rule sufficient to handle review of SB 32 projects for interconnection purposes.

The Solar Alliance recognizes that the Commission must provide guidance on what interconnection protocol should be followed on an interim basis until the Commission further considers the issue (either by assessing a settlement agreement regarding modifications to

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[25] CEERT Comments at p. 15.

[26] IREC Comments at p. 17.

Rule 21 or otherwise). In this regard, the Solar Alliance would note that a number of parties, given the current deficiencies in Rule 21, support the use of the IOUs' wholesale distribution access tariffs.[27] The Commission should proceed to adopt, on an interim basis, the use of the IOUs' WDATs for interconnection under the SB 32 program.

III. TARIFF ISSUES

A. Size of Eligible Facility

While increasing the capacity limitation of eligible projects from 1.5 to 3 MW, SB 32 authorizes the Commission to reduce the 3 MW capacity limitation for a particular electric corporation if such reduction "is *necessary* to maintain system reliability within that electrical corporation's service territory." Not surprisingly, SDG&E requests that the Commission exercise this authority so as to maintain a 1.5 MW project size limitation for SDG&E's FIT.[28] In support of this request, SDG&E cites the "unique" characteristics of its system,[29] specifically noting that "projects greater than 1.5 MW will likely be sited in SDG&E's back-country areas, where there is available land" and where the "distribution system design makes it difficult to interconnect substantial or large quantities of distributed generation that is not located relatively close to a substation, without requiring substation expansions."[30]

SDG&E made comparable arguments when the Commission was considering a

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27 PG&E Comments at pp. 23-24; SDG&E Comments at p.5; SCE Comments at p. 16; Clean Coalition Comments at pp 28-29; Solar Alliance Comments at pp.21-22.

28 San Diego Gas & Electric Company Comments to Section 399.20 Ruling Dated June 27, 2011, R. 11-05-005 (July 21, 2011) (SDG&E Comments), at pp. 11-14.

29 *Id.* at p. 11.

30 *Id.* at p. 12.

feed-in tariff program for projects up to 10 MW in size.[31] SDG&E pushed back against the suggested maximum size citing the same unique characteristics of its system and that such limitations "are likely to be particularly evident with projects greater than 1.5 MW which will likely be sited in SDG&E's back country areas, where there is available land." Ultimately SDG&E "recommend[ed] adoption of a ***5 MW*** project or smaller size cap for participation in the FIT program."[32] The size limitation under SB 32 is 3 MW. SDG&E has not illustrated why its system which apparently could accommodate 5 MW distributed generation systems two years ago is incapable of accommodating 3 MW systems today. SDG&E's request to maintain a 1.5 MW project size limitation for its FIT should be denied.

Similarly, SDG&E's accompanying request – i.e., if the Commission does not reduce the size limitation, then, with respect to projects greater than 1.5 MW additional contract obligations must be imposed[33] – is equally objectionable. In essence, what SDG&E is requesting is that projects greater than 1.5 MW in its service territory be punished by the imposition of several onerous contract provisions which, more likely than not, will render participation in the FIT program uneconomical.[34] A primary purpose of the FIT program is to provide a streamlined process which recognizes the inherently different risk profile between the smaller projects which would be candidates for the program and larger projects which participate in the IOUs' annual

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31 San Diego Gas & Electric Company Comments Regarding Administrative Law Judge Ruling on Additional Commission Consideration of a Feed in Tariff, R. 08-08-009 (April 10, 2009) at pp. 4-12.

32 *Id.* at p. 9.

33 SDG&E Comments at p. 15

34 For example, SDG&E has identified the following additional terms and conditions as being necessary for projects greater than 1.5 MW: (1) security requirements similar to the standard RPS RFO; (2)delivery guarantees and damages provisions; (3) CAISO penalty provisions; and (4) events of default provision such as that contained in SDG&E's pro forma RPS contract. *See* SDG&E Comments at p. 15.

RPS solicitations. SDG&E's proposed contract terms and conditions for projects larger than 1.5 MW blurs the lines between what is intended to be two distinct programs. As such these additional contract terms and conditions must be rejected.

B. <u>Deliverability and Resource Adequacy Requirements</u>

As Special Condition No. 9 of its proposed SB 32 tariff, SCE provides that "the Eligible Electric Generation Facility shall obtain Full Capacity Deliverability Status as a precondition to receiving payment under this Schedule." Similarly, SCE request that the Commission assure that whatever interconnection protocol is ultimately approved will address the studies required for certification for resource adequacy credit.[35] While the Solar Alliance recognizes that Section 399.20(i) requires that "[t]he physical generating capacity of an electric generation facility shall count toward the electrical corporation's resource adequacy requirement for purposes of Section 380," it submits that it is premature to require that the seller obtain full capacity deliverability status from the California Independent System Operator in order be an eligible generator under the SB 32 program. Rather, the Solar Alliance submits that the Commission should address this issue in a manner comparable to that of the Renewable Auction Mechanism program.

Specifically, the Commission rejected the IOUs' proposal to require full capacity deliverability status, and instead directed that "the IOUs should require the seller to apply for a deliverability study and achieve full deliverability status in the instances where no additional upgrades for deliverability purposes are needed or if a seller can obtain full deliverability with no additional costs to the seller," while directing the IOUs to work with its staff to determine the

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[35] SCE Comments at pp. 15-16. Currently the WDAT and the CAISO tariff do address this issue while Rule 21 does not.

appropriate procedural path to reevaluate this issue.[36] The Commission should follow the same protocol here.

C. Sunset Date

PG&E recommends that the Commission set a sunset date for the SB 32 program of January 1, 2014. In this regard, PG&E states that:

> Over the next several years, the IOUs will continue to contract for renewable resources through the RAM Program, RPS Solicitations, IOU-specific programs (such as PG&E's PV Program), and bilateral negotiations. At some point in the future, the IOUs may have executed a sufficient volume of RPS-eligible PPAs to ensure that they can satisfy their statutory RPS requirements. In this circumstance, it would no longer be necessary or appropriate for the IOU to be required to offer a Section 399.20 tariff and form contract if the RPS-eligible energy is no longer needed.[37]

PG&E's recommended sunset date should be rejected. First, even under the best case scenario the SB 32 program will not commence until early 2012, resulting, under PG&E's proposal, of an operation period of less than two years. A two year period of time may not be sufficient time for the market to respond to provide 750 MW of eligible projects. Second, PG&E argues that once the IOU has executed a sufficient number of RPS eligible PPAs to ensure meeting its 33 percent renewable obligation "it would no longer be necessary or appropriate" for the IOU to offer an SB 32 program. Such argument, however, does not account for the fact that contract execution does not equate to product delivery. Thus the fact that the IOU has executed a sufficient number of contracts to meet the renewable requirement does not provide reasonable basis for terminating the program. Finally, the statute requires that the IOU make the tariff available until the IOU meets its proportional share of the statewide cap of 750 MW. There is no provision for

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36 Resolution E-4414 (August 18, 2011) at p. 16.

37 PG&E Comments at p.25. SCE is proposes something comparable as a Special Condition in its SB 32 program tariff, stating that the tariff will be available until the earlier of SCE reaching its allocated MW under the program or the first year SCE's procurement of electricity products from eligible renewable energy resources equals 33 percent of SCE's retail sales in accordance with Public Utilities Code Section 399.15 (MP FiT Cap).

eliminating the tariff once the IOU purportedly meets its 33 percent RPS requirement. PG&E's requested sunset date must be denied.[38]

D. Seller Concentration Limit

PG&E proposes that a Seller concentration limit be established by the Commission that would limit a single Seller to executing no more than 10 MW of Section 399.20 form contracts in a single calendar year.[39] PG&E justification for imposing such a limit is that "because there is a MW cap on the amount of E-SRG form contracts that are executed, a single counterparty could effectively take up the entire program cap by executing multiple Section 399.20 form contracts."[40] PG&E does not indicate whether such a 10 MW limit would be per IOU service territory or statewide. PG&E's request for a seller concentration limit is premature.

SB 32 has increased the program size from 250 MW to 750 MW, all of which will be comprised of projects 3 MW or less. It is hard to fathom that a "single counterparty" or even several such counterparties could execute a sufficient number of contracts such that it would take up the entire program cap, or even one IOU's allocated portion of that cap. If, however, such did become a problem, the IOU could file an advice letter seeking a tariff change and imposing a seller concentration limit in its respective service territory.

IV. THE IOUS SHOULD BE DIRECTED TO UTILIZE THEIR AB 1969 CONTRACTS, MODIFIED TO ENSURE FINANCEABILITY

For facilities that are less than 1 MW, PG&E is proposing to use its existing E-

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[38] SCE proposes something comparable to PG&E as a Special Condition 7 in its SB 32 program tariff (Schedule MP-FIT), stating that the tariff will be available until the earlier of SCE reaching its allocated MWs under the program *or the first year SCE's procurement of electricity products from eligible renewable energy resources equals 33 percent of SCE's retail sales in accordance with Public Utilities Code Section 399.15 (MP FiT Cap).* Again tying the termination of the tariff to the IOU meeting its 33 percent RPS requirement is not consistent with the statutory language and should be denied.

[39] PG&E Comments at p.26.

[40] *Id.*

SRG form contract, which was approved by the Commission in conjunction with the AB 1969 program, with some modifications to implement certain requirements in Section 399.20. For projects that are between 1 and 3 MW in size, however, PG&E proposes using a modified version of its Renewable Auction MechanismProgram power purchase agreement (PPA). PG&E offers no explanation as to the need for two separate contracts. SDG&E makes a comparable submission, providing a pro forma contract for projects less than 1 MW which is based on its AB 1969 contract, while merely stating (but providing no contract) that for projects sized at 1 MW and larger, SDG&E proposes to use its Renewable Auction Mechanism Standard Contract with modifications to certain terms. Like PG&E, SDG&E proffered no explanation as to the need or justification for two separate contracts. Finally, SCE, differing from the other two IOUs, proposes to use a modified Renewable Auction Mechanism PPA for all projects. The Commission should reject the IOUs' proposals to use their Renewable Auction Mechanism PPAs as the basis for the standardized contracts to be offered under the SB 32 program.

In enacting SB 32, the legislature sought to expand the AB 1969 program. However, there was no intent to substantively modify the program's underlying intent which, as expressed by the Commission, was to provide a "simple, streamlined program" for the purchase of electricity by the IOUs from certain eligible generators.[41] The pro forma PPAs approved by the Commission for use in the AB 1969 program matched this simple, streamline approach. The Commission must carry this same approach into the implementation of SB 32.

The reality is that for smaller projects such as those targeted by SB 32 certain of the provisions contained in the IOUs' Renewable Auction Mechanism contracts will render financing too costly to make projects economical. Developers in the market for the project

[41] *See* Decision 07-07-027 at pp. 2 and 7.

financing of projects in the up to 3 MW range face particular obstacles related to contract terms (such as guaranteed energy production, the posting of development security, insurance obligations), all of which can make it very difficult to secure project financing at a reasonable cost. Absent the ability of developers to obtain financing, the SB 32 program will not be the robust program envisioned by the legislature as a means to assist the state in achieving its renewable goals.

That said, despite the more streamlined nature of the AB 1969 contracts, there are certain provisions in these contracts which have also impeded the ability of developers to obtain the necessary financing. This fact is evidenced in the limited number of AB 1969 projects which have come on line in the 2.5 years the program has been in operation.[42] As highlighted in the recently filed motion of the Clean Coalition for immediate amendments to SCE's AB 1969 SCE's CREST PPA,[43] the PPA's termination and contract modification provisions have resulted in almost uniform rejection of the contract by traditional commercial lenders.[44] Comparable provisions are contained in SDG&E's Customer Renewable Energy Agreement.[45]

Accordingly, the Commission should direct the IOUs to use their current AB 1969 pro forma contracts, updated to incorporate any changes required by statute and to make the necessary modifications to render them financeable, in the SB 32 program.

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42 SCE and PG&E have had 2.5 MW and 2.63 MW, respectively come on line under the program;see.http://www.sce.com/EnergyProcurement/renewables/crest.htm.and http://www.sce.com/EnergyProcurement/renewables/crest.htm.

43 *See* Clean Coalition Motion for Immediate Amendments of AB 1969 CREST Power Purchase Agreement , R. 11-05-005 (August 15, 2011)

44 The specific CREST PPA provisions referenced in the Motion are Section 4 (Term and Termination), Section 12 (Assignment) and Sections 14.2 and 14.4 (Contract Modification).

45 See SDG&E's Customer Renewable Energy Agreement Sections 4, 12, 14.2 and 14.4.

V. CONCLUSION

As set forth above, as well as in its opening comments, the Solar Alliance submits that the Commission should move forward expeditiously to implement SB 32. The Commission can do such by directing, *that on an interim basis*, an MPR based price should be utilized as the contract price and the IOUs' WDATs for interconnection. Moreover, consistent with the program's streamlined intent of the program, the IOUs should be directed to use their AB 1969 pro forma contracts modified only as statutorily necessary to contract with SB 32 generators.

Respectfully submitted this August 26, 2011, at San Francisco, California.

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Counsel for the Solar Alliance

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 "The Solar Alliances' Reply Comments to Section 399.20 ruling Dated June 27, 2011."

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 26th day of August, 2011, at San Francisco, California.

/s/ Jeanne Armstrong
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