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 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] comments on the issues and comments posed therein on the implementation of each statutory element of SB 32.

I. INTRODUCTION

SB 32 provides California another opportunity to enhance the availability of in-state renewable power sources. In implementing the provisions of the statute, the Solar Alliance requests that the Commission keep in mind the state's overarching goal of thirty-three percent renewable power by 2020. Specifically, the Solar Alliance believes that the statute should be implemented in a manner which will spur new development, eradicate unnecessary barriers to renewable facilities coming on-line, and provide such facilities a rate for their power which truly reflects the costs that the electric corporations are avoiding by purchasing from SB 32 generators in lieu of other sources of power.

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.

With these goals in mind, the Solar Alliance submitted briefs on March 7, 2011 and March 22, 2011 in the predecessor rulemaking to this proceeding.[2] Numerous other parties also participated in that round of briefing, providing the Commission an adequate record on which to implement SB 32. However, as noted in the June 27 Ruling, the recent passage of SB 2 1X by the California legislature altered one aspect of SB 32 -- the means by which the market price for the energy from SB 32 generators should be determined. The Solar Alliance submits that this is the sole issue which needs further deliberation by the Commission. Consistent with this view, the Solar Alliance submits the comments below which, with the exception of addressing the pricing issue and the recommended delayed implementation of certain aspects of the statute until 2012, maintain the views that it espoused in its earlier round of briefs.

II. PRICING ISSUES

A. Definition of Market Price of Electricity

SB2 1X (Section 399.20(d)(2)) requires that the "The commission shall establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with an electric generation facility….". Given this requirement, the June 27 Ruling appropriately asks for comment on how the market price of electricity should be defined in the context of implementing SB 32.[3] In this context, the Solar Alliance believes that the "market price of electricity" can be derived from either (1) the market prices for comparably-sized RPS-eligible renewable generation that the IOUs procure in compliance with California's RPS statutes and regulations (§399.20[d][2][A]), or (2) the long-run costs that the IOUs avoid from a new

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2 Opening Brief of the Solar Alliance and Vote Solar Initiative on the Implementation of Senate Bill 32, R. 08-08-009 (March 7, 2011) (Solar Alliance Opening Brief) ; Reply Brief of the Solar Alliance and Vote Solar Initiative on the Implementation of Senate Bill 32, R. 08-08-009 (March 22, 2011).

3 June 27 Ruling at p. 7.

conventional power plant producing power with the same attributes as the renewable generation in the RPS portfolio (§399.20[d][2][B]). Key attributes of the IOUs' RPS portfolios include (1) delivery to the California utilities at the transmission level; (2) full mitigation of major environmental impacts, such as water use and emissions of GHGs and criteria air pollutants; and (3) long-term fixed prices for power. This second market price is generally the price known as the "market price referent" (MPR), which the Commission has adopted annually since 2004.

Generally, the Solar Alliance believes that the "market price of electricity" as used in §399.20 refers to a baseload price that then can be time-differentiated using the utility's standard time-of-delivery factors to produce an appropriate price for a peaking profile of generation (for example, from solar PV) or for the profile of a non-peaking source of power supplied on an as-delivered basis when the renewable resource is available (such as wind). If the renewable resource provides a firm, baseload supply (e.g. biomass and geothermal), it will earn the full baseload price. This is how the time-differentiated MPR-based prices have been applied to small renewable projects under the AB 1969 program, for example.

B. Pricing Proposals

As noted above**,** the recent passage of SB 2 1X by the California legislature, altered *one* aspect of SB 32 -- the means by which the market price for the energy from SB 32 generators should be determined. By removing certain language from the statute – namely "the payment shall be the market price determined by the commission pursuant to Section 399.15"[4] – SB 2 1X allows for consideration of multiple approaches to the pricing issue. That said, the Commission should bear in mind, as the end of 2011 rapidly approaches, that SB 32 was enacted in October

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[4] As recognized in the June 27 Ruling (at p. 3), with the enactment of SB 2 1X, the price for electricity purchased from an electric generation facility under § 399.20 is no longer tied to the cost containment provision of the renewables portfolio standard (i.e., the MPR).

2009 – i.e., the Commission's obligation to craft implementing regulation was triggered two and a half years ago. Thus expedience should dictate certain of the Commission's actions. In order to meet the goal of full, or even partial, implementation by the end of 2011, certain accommodations must be made.

In this regard the Solar Alliance notes that certain of the pricing proposal presented on the record (as discussed below) have yet to be fully developed and may necessitate protracted proceedings to be fully vetted. In contrast, the Commission is familiar with the MPR (the means for setting it being fully vetted at the Commission) and intends to establish a 2011 MPR. The use of the MPR provides an expedient means for implementing SB 32.

That said, the Solar Alliance recognizes that there are other pricing proposals that have merit and should be further explored. Thus, the Solar Alliance would propose that the Commission implement SB 32 using the MPR, with certain adders as discussed below, but that such pricing mechanisms should 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.

1. Continued Reliance on the Market Price Referent

The Solar Alliance submits that there are significant benefits to continued use of the MPR as the basis for AB 1969 / SB 32 pricing. The MPR methodology is well-established through a long line of Commission decisions and resolutions,[5] and the process for updating the MPR methodology is relatively ministerial. The MPR represents the cost of alternative sources of generation that are avoided by new renewable generation, and this cost varies with expected

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5 *See* D. 03-06-071, D. 04-06-015, D. 05-12-042, D. 07-09-024, and D. 08-10-026, plus Resolutions E-3942, E-3980, E-4049, E-4118, E-4214, and E-4298 adopting specific MPRs for the years 2004-2009.

fossil fuel prices. Even though, under SB 2 1X, the MPR will no longer be used directly as the cost containment mechanism for RPS power, the MPR may continue to play an indirect role in RPS cost containment. In this regard, elements of the MPR methodology have become widely used in other ratemaking contexts. For example, the MPR gas forecast is being used by the California Independent System Operator in its testimony in the long-term procurement planning case, R. 10-05-006.[6] The costs of the MPR's combined-cycle plant also have been used in capacity prices for QFs (D. 07-09-040), in the E3 avoided cost model for energy efficiency, and in several E3 RPS, DG, and GHG calculators.[7] Finally, as the June 27 Ruling correctly observes, a 2011 MPR will be calculated, and a new RPS cost containment mechanism is unlikely to be adopted until sometime in 2012.[8] Thus, in the short-term the continued use of the MPR as the basis for SB 32 pricing represents a logical, quick-to-implement, and easy-to-administer foundation for SB 32 prices. The Solar Alliance's proposal for use of the MPR adjusted to reflect the time of delivery, plus the addition of a locational value factor, and how this combination achieves ratepayer indifference is set forth in its March 7 Opening Brief (at pp. 12-23). The Solar Alliance continues to support this proposal for the initial implementation of SB 32.

In this regard, the Solar Alliance notes that the June 27 Ruling questions whether use of the MPR requires the addition of new adders "as suggested by parties in their March 2011

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6 *See* Rulemaking 10-05-006, CAISO Testimony of Mark Rothleder served July 1, 2011, at 35, lines 22-24 and 36, line 13 to 39, line 4

7 *See* D. 07-09-040, at 98-100, using the 2006 MPR as the basis for firm capacity prices; also, D. 05-04-024, at 32-35 for the use of certain elements of the MPR in determining avoided costs for energy efficiency programs avoided cost; and the GHG, 33% RPS, and CSI cost-effectiveness calculators developed for the CPUC by Energy & Environmental Economics (E3), available at http://www.ethree.com/public_projects/cpuc.html .

8 Rulemaking 11-05-005, Scoping Memo and Ruling of Assigned Commissioner, dated July 8, 2011, at pp. 2-3.

Briefs."[9] The Solar Alliance submits that the statute requires that, at minimum, the Commission *must* consider such adders and that an adequate record has been developed to support their adoption. Thus Section 399.20 (e) provides:

> 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."

As detailed in the Solar Alliances' March 7 Opening Brief, wholesale distributed generation projects developed under SB 32 offer the potential for significant locational benefits. SB 32 projects can be strategically located and interconnected in a manner that optimizes the delivery of their power to load. As detailed below, these locational benefits include: (i) reduced distribution line losses; (ii) avoided distribution system costs, including reduced loading of distribution transformers at the substation level during peak periods (thus increasing transformer life) and/or avoided upgrades when wholesale DG is located on distribution feeders that are capacity constrained; (iii) avoided transmission system upgrades that are required to access remote renewable resources located far from load; and (iv) avoided transmission line losses and congestion costs as a result of the SB 32 projects' proximity to load centers. In order to achieve and SB 32 price which reflects the real and quantifiable avoided cost benefits that ratepayers derive from new renewable generation sited at favorable locations on the California electric grid.

2. Technology-Specific Rates

As noted in the June 27 Ruling, in earlier rounds of briefing, certain parties suggested implementing SB 32 using technology-specific prices for different types of renewable resources.[10] The Solar Alliance agrees that such prices could be developed. Indeed, the

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9 June 27 Ruling at p. 8.

10 *E.g.,* Agricultural Energy Consumers Association and the Inland Empire Utilities Agency, California Wastewater Climate Change Group, and FuelCell Energy.

modeling that the IOUs have performed in the current long-term procurement planning (LTPP) case includes projections of technology-specific, levelized prices for long-term power purchase agreements for a variety of renewable technologies.[11] These prices are based on current estimates for the costs of these technologies and the financing requirement for a reasonable return on investments in these resources. The IOUs' LTPP testimony uses these prices to develop cost metrics for a variety of scenarios for a 33% RPS in 2020. Similarly, the California Energy Commission (CEC) produces levelized costs for a wide range of renewable technologies in the Cost of Generation study that it prepares biennially in conjunction with its Integrated Energy Policy Report (IEPR).[12] As noted in the June 27 Ruling (p. 9-10), these estimates use cash flow models similar to the Commission-adopted MPR model. The Solar Alliance believes that these models include all of the principal assumptions and calculations necessary to determine levelized, technology-specific prices. Clearly, such models have been and are being used to model the results of the market for RPS generation. If the Commission were to find that such models are accurate and use reasonable input assumptions, they could be used to set technology-specific prices that would comply with either §399.20(d)(2)(A) or (B).

That said, the Solar Alliance is realistic enough to anticipate that parties are unlikely to agree on certain aspects of the structure or input assumptions needed for these models. As a result, significant effort would be required to validate these models for the purpose of setting SB

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[11] Rulemaking 10-05-006, Joint IOU Testimony served July 1, 2011, Appendix A, at p. A-50 and Table 30.

[12] The 2009 IEPR cost of generation report is the "Comparative Costs of California Central Station Electricity Generation" (CEC, January 2010), available at http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF

32 prices.[13] For example, since 2004 the Commission 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.[14] Although the Solar Alliance believes that effort has successfully reduced the effort and controversy involved in updating the MPR model, a similar substantial effort would be necessary to adopt comparable models for a wide range of renewable technologies, some of which are far less well-developed and have far fewer data sources than a conventional, widely-used fossil resource such as a CCGT. Actual RPS contract prices or the costs of specific proxy plants could be used to validate technology-specific prices determined from cash-flow models; however, up-to-date RPS contract prices are confidential and specific contract prices or proxy plant costs can reflect project-specific attributes that are not typical of generic projects of that technology. Finally, the costs of some renewable technologies – for example, solar PV – are changing rapidly. As a result, the use of technology-specific prices would commit the Commission to a regular administrative process to update those prices. As the Commission knows well from its long history with administratively-determined QF prices, such a process can be litigious and resource-intensive for all parties. In sum, although this option is feasible, it would be time-consuming and administratively-burdensome, and is unlikely to be the simplest or most expeditious means to implement SB 32. Thus, the Commission should not pursue it for the initial implementation of the statute.

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13 Particularly controversial inputs to these models are likely to be capital costs in the California or WECC market, capacity factors, O&M costs, and financing costs, including the capital structure, the costs of debt and equity, and tax benefits.

14 *See* footnote 5, above.

3. Rate Based on Power Purchase Agreements

The June 27 Ruling notes that when the Commission adopted the MPR in compliance with the then-existing provisions of §399.15, it determined not to adopt a market price based on prices found in power purchase agreements because, according to the Commission, the record did not "indicate that there are contracts sufficient in number or comparability to provide a basis for setting a market price."[15] The Ruling asks, given that a significant number of RPS solicitations have occurred since this time, whether a rate under §399.20(d) should be based on RPS power purchase agreement prices.

The Solar Alliance agrees that actual contract prices in RPS PPAs could be used as the basis for SB 32 prices. Such prices are a direct measure of long-term costs for new renewables "determined pursuant to an electrical corporation's general procurement activities as authorized by the commission," and thus clearly would be consistent with §399.20(d)(2)(A). As most RPS contracts are based on a fixed price for baseload power, to which is applied time-of-delivery factors, the Solar Alliance believes that it would be possible to calculate the average baseload RPS price for contracts of a certain vintage and term. Since the IOUs' RPS portfolios include the principal renewable technologies, it also may be possible to develop contract-based prices for specific technologies.

The Solar Alliance, however, sees four principal challenges to the use of data from actual RPS PPAs. Most important, the data is currently confidential, and parties may object that the public release of such data would bias solicitations for larger RPS projects. RPS contract prices do become public three years after contract deliveries begin,[16] but contract prices will be

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15 June 27 Ruling at p. 10, *citing* Decision 03-06-071 at p. 16.

16 Decision 06-06-066, at Appendix 1, Section VII, Parts F and G.

outdated by this time. Second, the signing of an RPS contract does not guarantee a viable project, and all RPS contracts do not result in successful projects. By the time that it is clear that an RPS project will come on-line successfully, the price for that contract is likely to be 2-5 years old, and may no longer be up-to-date even if it could be made public. Third, even if aggregated contract prices could be made public more promptly than individual contract prices, the aggregate prices may need to be adjusted if technology or financing costs are changing rapidly. Finally, and perhaps most important, PPA prices applicable to large RPS projects may be too low for much smaller SB 32 projects that do not have the same economies of scale as larger projects.

4. Market Based Rate

In earlier briefings, Southern California Edison Company (SCE) supported the use of an auction mechanism to set the SB 32 price. The Commission is using an auction approach to price the output of renewable generators from 5 MW to 20 MW in size, under the Renewable Auction Mechanism (RAM) adopted in D. 10-12-048. SCE proposed simply to extend the RAM to the smaller projects covered by SB 32 (3 MW or less in size), with certain modifications that SCE has proposed in a petition for modification of that order. The June 27 Ruling asks whether parties support such a market based approach.

The Solar Alliance questions whether a market based pricing approach is possible within the statutory confines of SB 32. Section 399.20(f) directs the Commission to make the SB 32 tariff "available to the owner or operator of an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis…." Clearly, if the tariff is made available only to the lowest bidders in an auction, it will not be not available "upon request" from a generator "on a first-come-first-served basis."

The more practical problem with the use of an auction mechanism to price small projects is the lack of pricing certainty and transparency for project developers. In many instances, the developers of small renewable projects will be smaller companies that lack the ability to fund development activities for projects whose costs may or may not exceed the revenue available at the unknown market-clearing price in the next SB 32 auction. If SB 32 prices are known in advance, developers can focus on those opportunities that will result in an economic project at the known MPR-based rate. Smaller developers also may lack the experience and expertise needed to bid accurately in a RAM-like auction. As a result, the RAM approach is likely to result in a greater number of uneconomic bids and increased numbers of failed projects. Thus, the use of a known and transparent SB 32 price will not only encourage more development activity, but more successful projects in this market segment.

If the Commission wishes to rely on a market-based mechanism, the Solar Alliance would prefer that the Commission derive the SB 32 price from the highest, market-clearing price of the successful bids from a market mechanism for projects of a comparable size, such as SCE's most recent SPVP auction or other auctions for projects less than 3 MW, and then make this price available to developers pursuing SB 32 projects. This price would be for a baseload product, derived from market-clearing auction prices using the utility's applicable time-of-delivery factors.[17] In this way, the price would be known in advance to developers, who then could ask to receive an SB 32 contract "upon request, on a first-come-first-served basis," as specified in§399.20(f). The auction-based price would apply until the next IOU PV Program or

[17] The Solar Alliance believes that the release of this limited amount of pricing data from RAM auctions would be consistent with the Commission's direction in D. 10-12-048 (the RAM decision) that "it is also important that the maximum amount of price information be available in order to gain public acceptance of the RAM" and that parties should "explore all reasonable means to make price and other information widely available" (D. 10-12-048 at pp. 76-77).

RAM auction, or until the utility's allotment of SB 32 capacity is filled if that occurs before the next auction.

III. NON- PRICING ISSUES

A. Increase Size of Eligible Facility to 3 MW

SB 32 increases the size of an eligible facility from 1.5 to 3 MW, but allows the Commission to reduce the 3 MW capacity limitation if it finds that "a reduced capacity limitation is necessary to maintain system reliability within that electrical corporation's service territory."[18] The June 27 Ruling proposes to implement the 3 MW provision by end of 2011 and request "comments on any further issues to be considered on capacity limitation under this program."[19] The Solar Alliance supports the Commission's immediate implementation of this provision in the statute and submits that there has been no showing that there is a need for the Commission to exercise its discretion to reduce the capacity limitation.

As noted by the June 27 Ruling, SB2 1X made no changes to the statutory provision which increased the eligible facility size. Thus, this issue has already been briefed in full. And while the June 27 Ruling requests that parties comment on "any further issues to be considered on capacity limitation under this program,"[20] the Solar Alliance would submit that its is premature for the Commission to determine that the reduction of the capacity size of projects is necessary in any electric corporation's service territory.

The standard which the Commission must use for determination to reduce the capacity limitation of SB 32 generators interconnecting to an electrical corporation's grid is one of

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18 Public Utilities Code Section 399.20(j)(2).

19 June 27 Ruling at p. 13.

20 *Id.*

"necessity," Meaning that it must be necessary "to maintain system reliability." It would be difficult for any electric corporation to make the necessary showing absent some experience with attempted interconnections of SB 32 generators over 1.5 MW. Accordingly, the Solar Alliance submits that the Commission should proceed to implement the 3 MW limitation in all electric corporations' service territory. If in the future, an electric corporation encounters issues with the interconnection of SB 32 generators over 1.5 MW, it may present such evidence to the Commission for a determination under Section 399.20(j)(2). Making such a determination now is premature.

B. Proportionate Share and Increased Program Cap to 750 MW

The SB 32 code section pertaining to the increase in the statewide megawatt cap from 500 MW to 750 MW and the allocation of those megawatts among the electrical corporations states as follows:

> An electrical corporation shall make the tariff available to the owner or operator of an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis, until the electrical corporation meets its proportionate share of a statewide cap of 750 megawatts cumulative rated generation capacity served under this section and Section 387.6. The proportionate share shall be calculated based on the ratio of the electrical corporation's peak demand compared to the total statewide peak demand.

As noted in the June 27 Ruling, SB 2 1X made no further modifications to this particular language contained in SB 32.

Thus the current code section, while not verbatim to the one contained in AB 1969 contains the same underlying concepts,[21] e.g., allocation to electrical corporations based on the ratio of its peak demand compared to statewide peak demand. Therefore the issues surrounding the allocation of the statewide MW cap has been previously vetted as part of the process

[21] *See* AB 1969, as amended by SB 380, amending Public Utilities Code Section 399.20 (e).

undertaken by the Commission to implement AB 1969, resulting in Decision 07-07-027. The Solar Alliance submits that there is no need to revisit this issue; that the procedures adopted in Decision 07-07-027 for AB 1969 feed-in-tariffs should be extended to the expanded program under SB 32. The June 27 Ruling supports this determination, concluding that "in the interest of administrative ease, it is reasonable to maintain the current allocation methodology."[22]

The Ruling, however, requests comments on whether the statute requires a recalculation of each utility's proportionate share of the cap due to the addition of publicly owned utilities to the program. The Solar Alliance submits that the answer to this question is "yes." Given the fact that this cap is statewide and is to be allocated between both investor-owned utilities and publicly-owned utilities, the allocation percentages achieved under AB 1969 cannot be maintained. Rather, all applicable electric corporations should provide the CEC with its system demand coincident with state peak demand in 2010. The CEC can once again use this information to allocate the MWs among the electrical corporations. Moreover, to maintain stability in the market and to assist in project development efforts by allowing developers to know how many MWs will be available under each electrical corporation's SB 32 tariff, consistent with the AB 1969 program, there should not be routine, periodic updates to the allocations.[23]

While the June 27 Ruling did not request comment on another element of this statutory provision – i.e., that the tariff shall be made available on a first come-first served basis – the

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22 June 27 Ruling at p. 14.

23 Under the adopted procedures for the implementation of AB 1969, there was to be no routine, periodic updates to the allocation of proportionate shares, but an electrical corporation was permitted to seek an adjustment when appropriate. The proponent of the change was required to use the same methodology for the reallocation as the initial allocation (utilizing the CEC if necessary) and present its proposal through a Tier 3 advice letter. *See* Decision 07-07-027, at p. 10.

Solar Alliance reemphasizes a proposal made in its March 7 Brief – that the SB 32 program be implemented on a measured basis, such that each electric corporation makes available 25 percent of its allocated capacity on a semi-annual basis. The reason for such measured approach is clear. First come- first serve has been interpreted by the Commission to mean receipt of the executed standard contract by the electrical corporation.[24] Under such interpretation, if, for example, all 750 MW are made available on "day one," there is a significant chance of a rush to market where the project queue could be filled within a matter of days. As there are no enumerated screening criteria which would narrow the projects which can execute a contract, the result could be an immediately jammed queue with an ensuing uncertain number of drop outs. A more measured approach will allow the Commission to better monitor the program, to assure that the SB 32 project queues are not becoming jammed with phantom projects and, if necessary, to alter the determination for when an electric generation facility is counted toward the electrical corporation's share of the MW cap.

C. Separate Tariffs

Currently each electrical corporation has two feed-in-tariff rate schedules -- one schedule for public water or wastewater agencies and one for all other qualifying customers. The June 27 Ruling finds it reasonable to direct each electric corporation to consolidate its two feed-in tariff rates schedules.[25] The Solar Alliance supports the consolidation and reserves the right to comment on specific provisions of the combined tariffs once presented by the electrical corporation.

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24 Decision 07-07-027, at pp. 11-12.

25 June 27 Ruling at p. 15.

D. Retail Customer Requirement Eliminated

As enacted by AB 1969, §399.20(b) required the electric generation facility be, among other things, "owned and operated by a retail customer" of an electrical corporation. SB 32 removed this requirement and inserted the language "located within the service territory of, and developed to sell electricity to…." As noted in the June 27 Ruling, SB 2 1X retains this modification and, as a result, § 399.20 applies "to those that are not retail customers of the electrical corporation and also to those that are not owners or operators of the electric generation facility."[26] The Ruling proposes 2011 implementation of this statutory provision. The Solar Alliance supports this proposition and requests that the clarifying language in the June 27 Ruling as to the Section 399.20's meaning be included in the Commission's implementation order.

E. Yearly Inspection and Maintenance Report

In order to ensure the safety and the reliability of the electric generation facilities, SB 32 requires that each owner of a facility provide to the electrical corporation on a bi-annual basis an inspection and maintenance report prepared by a California-licensed contractor.[27] As noted in the June 27 Ruling, SB2 1X did not change this provision. The Ruling, however, recommends that the Commission not implement this provision by end of 2011 and, instead, address this matter at the beginning of 2012. The Solar Alliance is not opposed to delaying implementation of this statutory provision, but submits that its resolution appears to be fairly straightforward.

Implementation of the biannual reporting requirement was vetted in the March 2011 Briefs. The issue did not generate significant controversy, but rather certain parties presented proposals which would allow for ready implementation of this provision. Thus, the Solar

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26 June 27 Order at p. 15.
27 Public Utilities Code Section 399.20(p).

Alliance recommended that Commission adopt a report modeled after the periodic testing documentation requirements of Rule 21. Such would require the owner/operator of the electric generation facility to perform all requisite maintenance activities at the intervals designated by the equipment manufacturer and to log the results of such tests. On a bi-annual basis, the log could be provided to the electrical corporation for review.[28] SunEdison made a comparable suggestion,[29] while PG&E recommended that the Commission establish a workshop to develop a simple form that can be used for bi-annual inspection and maintenance reports.[30] In short, parties previously commenting on this statutory provision emphasized the need for simplicity. Thus reaching agreement on the proper reporting format should be straight forward and could be resolved at the workshops to be scheduled in this proceeding.

F. Ten-Day Reporting Requirement of Request for Service under Tariff

SB 32 requires an electrical corporation, having received a request for a tariff, to post, within ten days, a copy of the request on its internet web site. In doing so, the posting must include the name of the city in which the facility is located, but information that is proprietary and confidential is to be redacted prior to the posting.[31] The June 27 Ruling recommends that the Commission implement this statutory provision by the end of the year and that the electric corporation be required to post the following data points: project name; status (e.g., operational, delayed); capacity (MW); expected GWh/yr; technology; price ($/MWh); vintage (e.g., existing,

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28 Solar Alliance Opening Brief at pp. 6-7.

29 Opening Brief of SunEdison LLC on Implementation of Senate Bill 32, R. 08-08-009 (March 7, 2011) at pp. 8-9.

30 Reply Brief of Pacific Gas and Electric Company Regarding the Implementation of Senate Bill 32, R. 08-08-009 (March 22, 2011) at p. 7

31 Public Utilities Code Section 399.20(m).

new); term (years); location (City); contract execution date; online date/contracted delivery date; and achievement of the commercial delivery date within 18 months (yes or no). [32]

The Solar Alliance submits that the recommendation made in the June 27 Ruling goes a long way towards making the posting useful to the industry in assessing the level of projects which have requested service under the SB 32 tariff, the likelihood of those projects coming on-line, and the remaining capacity available in the program. That said, the Solar Alliance requests that a few additional data points be added – (1) name of developer; (2) original bid capacity; and (3) installed capacity. The Solar Alliance suggests that these additional data points will provide a needed benchmark in determining the likelihood of projects being delivered a bid.

G. Implementation vis-à-vis Publicly-Owned Electric Utilities

SB 32 added §387.6 to the Public Utilities Code which requires local publicly owned electric utilities to offer feed-in tariffs to owners or operators of electric generation facilities within its service territory. The June 27 Ruling recommends that this provision be implemented immediately and requests comments on any interaction between the implementation of this statutory provision with the implementation of SB 32 vis-à-vis the investor owned utilities. [33] The Solar Alliance has already noted that the inclusion of the publicly owned utilities within the 750 MW statewide cap will necessitate a recalculation of the percentage allocation to each utility. Beyond this, the Solar Alliance does not take any position on the implementation of SB 32 as it relates to publicly owned utilities.

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[32] June 27 Ruling at pp. 16-17.

[33] June 27 Ruling at p. 17.

H. Utility Discretion to Deny Tariff

SB 32 provides an electrical corporation with the opportunity to deny an electric generation facility's request to sell energy to the electrical corporation under the posted tariff, under the following circumstances:

> (1) The electric generation facility does not meet the requirements of this section; or
>
> (2) The transmission or distribution grid that would serve as the point of interconnection is inadequate; or
>
> (3) The electric generation facility does not meet all applicable state and local laws and building standards, and utility interconnection requirements; or
>
> (4) The aggregate of all electric generating facilities on a distribution circuit would adversely impact utility operation and load restoration efforts of the distribution system.[34]

The June 27 Ruling proposes to not implement this provision by end of 2011 and requests comment on the existing procedure relied upon by electric utilities to deny tariff requests.

As noted in the Solar Alliance's March 7 submission, implementation of this section of the statute requires both clarification of certain statutory terms as well as direction by the Commission that electrical corporations must make certain data available to developers. Absent resolution of the issues raised by the Solar Alliance and others, the Solar Alliance supports delaying implementing this provision in the statute.

I. Tariff or Contract Termination Provisions

SB 32 added subsection (l) to §399.20 to provide for contract termination before the contract expiration date in certain circumstances. Specifically:

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[34] Public Utilities Code Section 399.20(n).

An owner or operator of an electric generation facility electing to receive service under a tariff or contract approved by the commission shall continue to receive service under the tariff or contract until either of the following occurs:

(1) The owner or operator of an electric generation facility no longer meets the eligibility requirements for receiving service pursuant to the tariff or contract.

(2) The period of service established by the commission pursuant to subdivision (d) is completed.

The June 27 Ruling proposes to not implement this provision by end of 2011 and request comment on the existing procedure relied upon by electric utilities to terminate contracts.

The Solar Alliance will reserve comment on this issue until it has the opportunity to review the pro forma contract language which the utilities have been directed to file on August 3, 2011. That said, however, if the filed language imposes conditions which are in excess of those approved by the commission for the current AB 1969 contracts, the Solar Alliance would recommend continuation of those provisions while this issue is being resolved.

J. Expedited Interconnection Procedures

SB 32 added subsection (e) to §399.20 to provide that an electric corporation shall provide expedited interconnection procedures for a facility that is connected on a distribution circuit and generates electricity in a manner to offset peak demand on the electric circuit. The statute does not set forth what those procedures should be, leaving that to Commission determination. The June 27 ruling proposes to not implement this provision by end of 2011.

The Solar Alliance is concerned that absent implementation of this statutory provision by year end, it will remain unclear what interconnection processed will be utilized for SB 32 projects. The Solar Alliance notes that, with respect to its implementation of AB 1969, the Commission addressed the need for expedited interconnection so as "to prevent interconnection from becoming a barrier to completion,"[35] by requiring the electric corporations to follow the interconnection procedures set forth in Rule 21. While the Solar Alliance ultimately favors the use of the Rule 21 process, it is concerned that Rule 21 is not currently equipped to handle review of SB 32 projects absent significant modification. Specifically, under the current Rule 21 construct, given the wholesale sale relationship which will exist with the interconnection of an SB 32 generator, the generator will not be able to pass the simplified interconnection screens under the Rule, thus necessitating an interconnection study. The study process under Rule 21 is broad and does not contain any timeframe assurances of when an interconnection study will be completed. Moreover, the Rule does not address queuing and the order of studying projects.[36] These deficiencies need to be rectified prior to the approval of Rule 21 as the "expedited interconnection" procedures required under SB 32. To this end, the Solar Alliance would recommend that through its decision on the implementation of SB 32, the Commission initiate a stakeholder process for the revision of Rule 21 to be overseen by the Energy Division with a directive that the IOUs file revised Rule 21 tariffs via a Tier 3 Advice Letter no later than August 1, 2012.[37]

In the interim, the IOUs should be directed to use the wholesale distribution access tariff (WDAT) for the interconnection of SB 32 projects. This process entails a three part interconnection study process that imposes timelines for completion of studies, and requires the

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[35] Decision 07-07-027, at p.40.

[36] Queuing procedures are important because they determine who pays for upgrades when multiple facilities will interconnect to the same feeder.

[37] The Solar Alliance is aware that a Rule 21 Working Group currently exists with the purported purpose of addressing needed changes in the Rule. Given the degree of necessary changes in the rule and the controversy they may engender, the Solar Alliance submits that a Commission directed process will be more effective and provide the necessary degree of accountability to achieve the intended goal.

IOUs to provide cost estimates for performing studies in advance of their performance and to refine the cost estimates of constructing interconnection facilities and network upgrades as each of the studies is completed. As this systematic process is contained in the WDAT, the Solar Alliance recommends that the electric corporations be required to utilize the interconnection procedures set forth in the WDAT until such time as the Commission rules on the IOUs' revised Rule 21 filings as discussed above.

K. Adjustments for Small Electric Utilities

The statute authorizes the Commission to modify or adjust the applicability of SB 32 for any electric corporation with less than 100,000 service connections, as individual circumstance merit. Based on the goals of administrative ease, reducing costs of implementation, the June 27 Ruling recommends an exemption from the program for all electrical corporations with less than 100,000 service connections.

The Solar Alliance has no comments regarding the recommended implementation of this provision at this time but reserve the right to submit reply comments on this issue.

L. Refunds of Other Incentives

SB 32 provides that any owner/operator of an electric generation facility that received ratepayer-funded incentives in accordance with either the California Solar Initiative program or the Self-Generation Incentive Program (SGIP) and participated in a net metering program is eligible for an SB 32 tariff *provided* that it either repays the incentives it had received or demonstrates that ratepayers had received sufficient value from the incentives.[38] The ruling recommends delaying the implementation of this provision to 2012. The Solar Alliance

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[38] Public Utilities Code Section 399.20(k)(2).

questions the practicality of this recommendation as it is unclear how, during the interim period, the SB 32 program would address eligible generation facilities which had previously participated in the CSI or SGIP. For example does delayed implementation of this statutory provision mean that for the time being that owners of eligible generation facilities will *not* have to refund any incentives received from the CSI or the SGIP? Or does it mean that during this interim period, consistent with the AB 1969 program, a system which had received CSI or SGIP incentives would be precluded from converting to a SB 32 tariff? At minimum, clarity for the interim period is needed.

Given that some action by the Commission with respect to the statutory provision is needed to allow the SB 32 program to move forward, the Solar Alliance would submit that the Commission should proceed to address and resolve implementation of this facet of SB 32 in 2011. In this regard, the most expeditious means of achieving implementation would be for the Commission to preclude systems that have received a CSI or SGIP incentive from converting to a SB 32 tariff.

While recognizing that the provision allowing for CSI or SGIP systems to participate in SB 32 is part of the statute, the Commission, in determining a means, if any, to implement it, should bear in mind that it does not serve the goal of bringing new renewable resources on-line, would be administratively difficult and cumbersome to implement, and at least with respect to systems which have been have functioning under the CSI program, is in contravention of SB 1. With respect to this latter point, it must be noted that facilities receiving incentives through the CSI program are not developed with a primary purpose of selling electricity to a utility. Rather, such a facility is designed to serve on-site load. Indeed, Section 27882(a)(1) of the Public Resources Code -- which SB 32 does not amend or supersede -- provides that one of the required criteria for receiving funding under the CSI is that the "solar energy system *is intended primarily to offset part or all of the consumer's electric load*." This is in direct conflict with SB 32's statutory requirement that the facility *be developed to sell* electricity to an electrical corporation.

Given the conflicting statutory language, the Commission should approach this issue from the overarching state goal of increasing the availability and use of renewable power. SB 32 should be viewed as an opportunity to spur new development and provide an additional source of renewable energy to be applied toward the state's RPS goal. Allowing generators operating under either the CSI or SGIP program to convert to the SB 32 program does not enhance the overall opportunity for the development of new renewable power in the state.

Finally, ensuring compliance with the statutory directive would require either (1) the electrical corporation to determine the exact amount of incentives which it has remitted to an electric generation facility under the CSI or SGIP program and the Commission to establish a means to retrieve those funds and ensure that ratepayers are appropriately credited, or (2) the Commission to establish some process by which CSI or SGIP generators could demonstrate on a case by case basis that ratepayers had received sufficient value for the incentives the generator received. This could be an administratively burdensome task.

M. Performance Standards

SB 32 directs the Commission to establish performance standards for electric generation facilities that seek to sell energy pursuant to an SB 32 tariff which are over one megawatt in size. The stated purpose of these standards is to ensure that those facilities are constructed, operated, and maintained to generate the expected annual net production of electricity and do not impact system reliability.[39] The June 27 Ruling does not make a recommendation regarding the

[39] Public Utilities Code Section 399.20(j)(1).

implementation of this portion of the statute.

In order to ensure that all SB 32 projects are operating under the same set of rules, the Solar Alliance would support immediate implementation of this section of the statute and the use of the following performance standards (which are currently being utilized by Southern California Edison as part of its renewable RFP program) for SB 32:

ffi Seller's Energy Delivery Obligation (over a two year period) equals one hundred forty percent (140%) of the Expected Annual net energy production (non-wind intermittent, e.g. solar only).

ffi Seller's annual energy Delivery Obligation equals the P-95 Value in Final Wind report (wind only).

ffi Seller's Annual Energy Delivery Obligation equal ninety percent (90%) of the Expected Annual Net Energy production (base load renewables only).

IV. CONCLUSION

The Solar Alliance believes that SB 32 can be another valuable tool to use for reaching the state's overall renewable goals. It has, however, been over two years since the legislation was originally enacted. The Solar Alliance urges the Commission to move forward expeditiously to achieve implementation. The Solar Alliance submits that the proposals set forth in its March 7 Opening Brief in conjunction with the recommendations stated above will allow the Commission to do so.

Respectfully submitted this July 21, 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 "The Solar Alliance's Comments to Section 399.20 Ruling Date 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 21st day of July 2011, at San Francisco, California.

/s/ Jeanne Armstrong
Jeanne Armstrong

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