BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

THE DIVISION OF RATEPAYER ADVOCATES' COMMENTS TO SEC. 399.20 RULING ISSUED JUNE 27, 2011

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I. INTRODUCTION

The Division of Ratepayer Advocates (DRA) respectfully submits these Comments pursuant to the June 27, 2011 Administrative Law Judge (ALJ) Ruling[1] requesting party comments on the implementation of certain amendments to Public Utilities Code §399.20 per Senate Bill (SB) 32 and SB 2 1X. DRA's comments follow the structure established in the ALJ's Ruling. To the extent DRA does not have a recommendation on a particular issue listed in the Ruling, it has been specifically indicated below, while reserving the right to address these issues in reply comments.

II. DISCUSSION OF SPECIFIC ISSUES

1. Background

DRA has participated in the implementation of SB 32 and submitted both opening and reply briefs in March 2011 in response to the January 27, 2011 Administrative Law Judge's *Ruling Setting Schedule for Briefs on Implementation of Senate Bill 32.* DRA's previous comments provided various recommendations regarding the implementation of

[1] *Administrative Law Judge's Ruling Setting Forth Implementation Proposal for SB 32 and SB 2 1 X Amendments to Section 399.20*, June 27, 2011 (June 27, 2011 Ruling or Ruling), p. 1.

certain statutory changes to §399.20 per SB 32. The enactment of SB 2 1X resulted in significant changes to the current Renewables Portfolio Standard (RPS) program. Accordingly, it is necessary to reevaluate some of the aspects of SB 32 and §399.20 to ensure compliance and conformity with the new renewable program standards. DRA continues to support the Commission's advancement of distributed generation renewable energy programs as a cost effective means of meeting California's renewable energy mandates and providing opportunities for small-scale renewable developers to participate in the State's renewable energy market. An effective Feed-in Tariff (FiT) program[2] under §399.20 is a critical component of the 33% RPS goal due to the program's potential to provide cost-effective near-term renewable energy for Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).[3] Moreover, an effective FiT program will help advance the distributed generation (DG) market in California. To ensure program success, DRA emphasizes the following recommendations to the Commission:

1. Given the recent changes in the renewable energy market in California, DRA believes it is reasonable to transition from basing the tariff price of §399.20 from the current market-price referent (MPR) to a net energy metering surplus compensation rate as adopted by the Commission in Decision (D.)11-06-016.
2. The Commission should consider the issue of refund of incentives in the 2011 timeframe instead of at the beginning of 2012. DRA believes it is critical to have this component of the program in place before the program commences in order to ensure fair pricing for all market participants and for the ratepayers who funded the incentives.

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[2] DRA uses Feed-in Tariff (FiT) and SB 32 interchangeably throughout these comments.

[3] DRA's Comments refer collectively to PG&E, SCE and SDG&E as "Utilities."

2. Implementation Goals

The June 27, 2011 Ruling announces the ALJ's intention of establishing a schedule that allows for full or partial implementation of the SB 32 and SB 2 1X by the end of 2011. Specifically, the Ruling requests party comments on the goal of implementing certain specified amendments to §399.20 in 2011, while deferring other issues until 2012. DRA supports the Ruling's stated goal to implement the following aspects of SB 32 and SB 2 1X before the end of 2011: determination of price, elimination of separate tariffs, elimination of the retail customer requirement, increase of the facility size to 3 megawatts (MW), adjustment of the program cap to 750 MW, the 10-day internet posting requirement for new tariff requests, the exemption for small electric utilities, and coordination with publicly owned utilities.

The Ruling's stated goal is to implement the remaining issues in 2012, including yearly inspection and maintenance reports (§399.20 (p)), denial of tariff requests (§399.20 (n)), contract termination provisions (§399.20 (l)), and the expedited interconnection process (§399.20 (e)). DRA supports deferral of these issues, but opposes the Ruling's proposed deferral of the issue of the refunds of other incentives (§399.20(k)). DRA recommends that the Commission consider the refunds of other incentives issue in 2011. A determination regarding the refund of incentives from customers who switch from a ratepayer-funded incentive program such as the California Solar Initiative to the FiT should be in place before this phase of the SB 32 program begins in order to ensure fair pricing for all market participants and for the ratepayers who fund the incentives. As explained in Section 4.12 of these comments, *Refund of Incentives*, a determination regarding the refund of these incentives is as critical as a determination of the pricing for the FiT program.

3. Compliance with SB 2 1X: Determination of Market Price

DRA agrees that, in light of SB 2 1X, the Commission should reevaluate the options to determine the market price. Although DRA previously supported the use of the Market Price Referent (MPR) to determine the SB 32 price, SB 2 1X removes the Commission's responsibility to calculate the MPR and it is uncertain whether the Commission will continue to calculate the MPR in years subsequent to 2011. Thus, it is appropriate for the Commission to explore new price methodologies for the FiT program.

DRA offers the following responses to specific price-related questions posed by the June 27, 2011 Ruling.

3.1 Definition of Market Price

1) *Define market price of electricity as used in § 399.20. Is there one market price of electricity relevant to all types of electricity procurement or are there different market prices depending on the type of electricity that is being procured? For example, is there a unique market price of electricity for the market segment targeted in § 399.20? Does the market price of electricity include all types of electricity contracts and technologies that a utility procures or a subset of contracts and technologies? If you propose a subset, please define the subset.*

From a ratepayer perspective, there should only be one market price of electricity. Because specific renewable mandates exist, it makes sense to add a renewable premium for RPS-eligible electricity. However, there is no other salient difference between the resources procured under FiT as under other RPS programs such as Net Energy Metering and even RPS contracts. The Commission should not choose "winners" in terms of technology or facility type by creating different prices for each. Instead, the renewable market – which has grown remarkably in the past several years and is becoming mature – should be allowed to function freely. The Commission should determine a single, consistent, pricing mechanism for renewables that includes adjustments for time of delivery (TOD). Such a pricing mechanism will result in consistency between programs, administrative simplicity, regulatory transparency, and will appropriately allow the market to determine which technologies move forward.

3.2 Continued Reliance on Market Price Referent

2) *Explain whether the price for electricity purchased under § 399.20(d), as amended by SB 2 1X, must or should be based on the MPR as currently calculated.*
3) *Explain whether the price for electricity purchased under § 399.20(d) must or should be based on the MPR as currently calculated with the addition of new adders, as suggested by parties in the March 2011 briefs.*
4) *Explain the benefits and the drawbacks of continuing to use the MPR as the basis of the price for the program under § 399.20 given the statutory changes.*
5) *Under the current RPS program rules each annual RPS Solicitation triggers an update to the MPR values. Consistent with CPUC decisions, Energy Division staff will calculate a 2011 MPR for the 2011 RPS Solicitation. Due to the statutory changes in SB 2 1X, it is not clear whether the Commission will continue to calculate an MPR to establish an RPS cost limitation. Parties should explain whether a new trigger for an MPR update is necessary and/or a schedule for how the MPR should be updated going forward.*

DRA's March 2011 opening brief and reply brief recommended the continued use of the MPR with adjustments for TOD factors as the appropriate market price rate for the FiT program.[4] For reasons discussed below, DRA now advocates its preference that the SB 32 tariff be derived from the net energy metering surplus compensation rate (NSC rate). DRA's primary concern with a continued reliance on the MPR is the uncertainty surrounding whether or not the MPR will be calculated in future years. In light of this uncertainty, DRA believes that it is appropriate for the Commission to consider additional price methodologies for the program and believes the NSC rate should be adopted as the appropriate market price for the SB 32 FiT program.

[4] See DRA Opening Brief, March 7, 2011, pp. 7-8; DRA Reply Brief, March 22, 2011, pp. 4-5.

Should the Commission decide to adopt the MPR as the appropriate market price for the FiT program, DRA does not agree with parties who advocate for including other adders to the MPR. With the exception of TOD adjustments to the price, no other adders are warranted as the MPR already encompasses the eight mandatory considerations for calculating the FiT price as specified in SB 2 1X.[5] Satisfaction of all eight mandatory considerations is certainly a benefit of the MPR should the Commission choose to adopt the MPR. Moreover, as an established value, DRA also finds the MPR to be a reliable metric which parties are familiar with.

Despite these benefits, DRA again emphasizes that the drawbacks of using the MPR include the uncertainty of the metric's existence going forward and how this uncertainty could affect participation in the FiT. In addition, some participants have found that relying on the MPR metric as a price point is an unrealistically low/unachievable price point for certain technologies and, accordingly, use of the MPR may have a negative impact on the overall success of the program.

Due to the uncertainty of the MPR calculation in future years, DRA advocates for establishing the SB 32 tariff on the NSC rate. The NSC rate is an established tariff that is based on market prices and adjusted for environmental attributes. These components of the price are publicly available and provide certainty of price stability to future FiT participants. DRA discusses the NSC rate below under question 11.

3.3 Additional Pricing Proposals

3.3.1. Technology-Specific Rates and Product-Specific Rates

[*Questions 6 - 8*, Ruling, p. 9]

As stated in the Ruling, some parties recommended using a technology specific rate for different types of renewable resources. DRA does not agree that a technology-

[5] See Ruling, p. 6 for list of mandatory considerations.

specific or product specific proposal is a desirable option for the FiT/SB 32 program. The process of determining the appropriate rate for each eligible technology would be time consuming and arduous and, as a result, may delay the Commission's intent to finalize the pricing mechanism for the program by the end of 2011. Furthermore, DRA believes that calculating a specific rate for each renewable technology conflicts with the ratepayer indifference clause and that selecting particular technology-based price points does not allow the renewable market to operate freely and with full competitiveness between technologies.

3.3.2. Market-Based Rate

[*Question 9*, Ruling, p. 10]

Although DRA supports the Renewable Auction Mechanism (RAM) and competitive solicitations under the RPS program, DRA does not support SCE's proposal that the price under §399.20 be based off the results of the RAM auction. DRA's primary concern with this proposal is that it does not offer a price guarantee for potential FiT participants due to the uncertainties of the RAM auction outcomes. Although the first RAM auction is scheduled to occur later this year per Resolution E-4414, the results of the auction are unknown and it is unclear how successful the first auction will be. Moreover, DRA is concerned about the potential for gaming that could result from relying on the RAM auction results to set the FiT program price.

3.3.3. Rate Based on Power Purchase Agreements

[*Question 10*, Ruling, p. 11]

DRA believes that a FiT program price based on actual Power Purchase Agreements (PPAs) is problematic for several reasons. First, the Commission would have to ensure that any PPA prices used for FiT comply with Decision.06-06-066, which requires market sensitive data to remain confidential for three years into the future.[6] Due to the three-year lag to disclose confidential, market-sensitive data, under this proposal the FiT program price would be based on RPS PPA prices that are significantly outdated. Recent prices for solar PV and other renewable technologies have declined over time and a FiT program price based on 2008 or earlier PPA prices would not allow the Utilities or ratepayers to capitalize on these price declines. Second, there have been a number of RPS PPAs that have been renegotiated or amended with a resulting increase in the contract price. Such price increases could skew the weighted average price for a particular subset of PPAs if these renegotiated prices are taken into consideration.

> *11) Provide all relevant details for other alternate pricing proposals, if any, consistent with the provisions of SB 2 1X.*

DRA agrees that, in light of SB 2 1X, the Commission should reevaluate the possible methodologies available to determine the market price. As noted above, DRA has previously supported the use of the MPR to determine the FiT price and DRA would not object to the use of the MPR based price in the short-term. An MPR based price would be acceptable for the 2011 timeframe until the California Energy Commission (CEC) has calculated the price of the renewable energy credit (REC) green attribute component.[7] However, SB 2 1X removes the Commission's responsibility to calculate the MPR and it is DRA's understanding that the MPR may no longer be calculated by the Commission after 2011. Thus, a new pricing formula may be needed. One potential long-term solution is the already approved price for renewables adopted in D.11-06-016 which approved a rate for Net Surplus Compensation (NSC).[8] That price combines the

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[6] Interim Order 1: "Where we find that data are market sensitive pursuant to Pub. Util. Code § 454.5(g) or otherwise entitled to confidentiality protection, in most cases, we adopt a window of confidentiality for Investor-Owned Utility (IOU) and Energy Service Provider (ESP) data that protects it for three years into the future, and one year in the past." (D.06-06-066, p. 80.)

[7] See DRA Opening Brief, March 7, 2011, pp. 5-6.

[8] Adopted on June 9, 2011.

price for brown power with a renewable premium.[9] The renewable premium will be determined once the CEC completes its determination of an interim proxy rate derived from the WECC average renewable energy premium, published by the Department of Energy. All of these numbers will be public.

3.4 Additional Pricing Questions

> *12) Identify relevant data sources that could be used to implement any proposed methodology and whether the data used to calculate the rate should be derived from public or confidential data. Please comment on the appropriateness of the data sources as identified by parties in opening comments, such as Fuel Cell Energy and CALSEIA.*

DRA recommends that, for administrative simplicity and transparency, public sources be used for the calculation of the appropriate market price. Although it is not impossible to consider confidential sources, the use of confidential data is unfair to parties who do not have access to this data. As discussed above, D.11-06-016 approved a rate for NSC that utilizes publicly available data.

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[9] The brown power price is determined by averaging the CAISO's default load aggregation point (DLAP) price for the IOU during the hours the facilites will most likely be generating. (See D.11-06-016, pp. 2-3.)

> 13) *Explain how often the price under § 399.20(d) should be calculated given your preferred price calculation approach. The price may be calculated once, at regular intervals, such as annually, or in response to a triggering event. For example, in March 2011 briefs, CALSEIA proposed that the price be modified quarterly and be increased or decreased based on market participation. The California Solar Initiative presented a different model for reducing prices over time in which incentive rates decline over the life of the program in multiple steps triggered by solar capacity additions to facilitate market transformation.*

The simplicity of DRA's proposal to adopt the NSC rate is not just that this rate has already been approved by the Commission but that, once approved, the rate never requires recalculation by the Commission because the NSC rate is derived from the "default load aggregation point" or DLAP price.

3.5 Ratepayer Indifference

> *In March 2011 briefs, parties addressed the requirement that "ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electric generation facility receives service pursuant to the tariff," (§ 399.20(d)(3)). Some, including CEERT, stated that ratepayers are indifferent to any avoided cost rate and others found ratepayer indifferent to any rate that is value based. These parties included, among others, CALSEIA and Clean Coalition. Clean Coalition also cited the Commission's application of a customer indifference provision in the implementation of AB 1613.7 Please respond in comments to the following questions:*
>
> 14) *Respond to these interpretations of "ratepayer indifference" and explain how the SB 2 1X amendments to § 399.20(d) and any new pricing proposal that you suggest pursuant to these amendments impact these interpretations.*

As with the FiT, the NSC required ratepayer indifference. Specifically, Public Utilities Code Section 2827, established by AB 920 (Huffman) (2009), contains the following language: "The net surplus electricity compensation valuation shall be established so as to provide the net surplus customer-generator just and reasonable compensation for the value of net surplus electricity, while leaving other ratepayers unaffected."[10] In D.11-06-016, the Commission's implementing Decision adopted only last month, the Commission directly interpreted that statutory language as one of ratepayer indifference.[11]

Both NEM and FIT customers provide electricity and RECs that the Utilities may use to comply with the RPS. The implementation of both of these programs is contingent upon ratepayer indifference. Paying an equal rate under each tariff makes sense for ratepayers. The resources have a lot of similarities in the way they are structured because they are both must-take renewable resources under a standard tariff. They both provide similar value to ratepayers. The Commission found in D.11-06-016 that the approved rate for NSC satisfies the "ratepayer indifference" requirement for that resource. Since FiT provides a very similar resource, DRA contends that the same rate would fulfill the indifference requirement mandated by AB 920 for NSC and by SB 32 for the FIT program.

3.6 FERC Order 134 FERC ¶ 61,044 = Order Denying Rehearing

> *With the statutory amendments set forth in SB 2 1X, parties are provided with an opportunity to offer additional comments on the impact of federal law on the implementation of § 399.20. It is not necessary to reiterate the positions set forth in the March 2011 briefs.*
>
> *15) Please indicate how those positions have changed, if at all.*

DRA does not have any additional comments at this time but does reserve the right to address this issue in reply comments.

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[10] P.U. Code Sec. 2827 (h)(4)(A).

[11] See D.11-06-016, pp. 34-37.

4. Compliance with SB 32

The provisions added to § 399.20 by SB 32 are set forth below. This ruling identifies those provisions that we propose be implemented by the end of 2011 and those provisions that will be addressed in 2012.

16) Parties are requested to comment on this proposal.

As stated above, DRA supports the Commission's categorization and advancement of several aspects of SB 32 and SB 2 1X before the end of 2011 but requests that the Commission consider the refund of incentives issue by the end of 2011.

4.1 Increase Size of Eligible Facility to 3 MW

17) Explain any further issues to be considered on capacity limitation under this program and next steps necessary to implement the provision. To implement § 399.20(b)(2), tariff language and form contracts may need to be amended. The investor owned utilities should submit tariff changes or revised contract language, if any, to implement this change with comments on July 21, 2011 and July 28, 2011.

DRA continues to support an increase in the FiT size to 3 MW.[12] DRA agrees with the Commission that the Utilities and Publicly Owned Utilities (POUs) are in the best position to identify the necessary changes to their tariffs in order to reflect this increase in program capacity.

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[12] See DRA Opening Brief, March 7, 2011, p. 4.

4.2 Proportionate Share and Increased Program Cap to 750 MW

18) *Explain the drawbacks and benefits to relying on the existing methodology for calculation of proportionate share. Does the statute require a recalculation of proportionate share based on the addition of publicly owned utilities? Would the Commission's calculation of proportionate share for local publicly owned utilities be restricted by any jurisdictional limitations?*

DRA continues to support the use of the current methodology to calculate the allocation of capacity to Utilities and POUs for the FiT program. DRA believes it would be appropriate to recalculate the capacity allocation now in order to adequately incorporate each electrical corporation and POU. As DRA previously stated, the CEC's *California Energy Demand 2010-2020 Commission Adopted Forecast* report should be used.[13]

4.3 Separate Tariffs

Based on the language of § 399.20, it appears reasonable to direct electric corporations to consolidate the two rate schedules [one schedule for public water or wastewater agencies and a separate schedule for all other customers]. Consolidation of tariffs may decrease transaction costs by simplifying the administration of the program.

19) *This ruling proposes to implement this provision by end of 2011. Explain the next steps necessary to implement this request.*

DRA continues to support the consolidation of tariffs, as described in its March 7, 2011 brief, because consolidation simplifies program administration and may decrease transaction costs. DRA believes the Utilities are in the best position to provide details on how they plan to consolidate the two rate schedules for this phase of the program.[14]

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[13] See DRA Opening Brief, March 7, 2011, pp. 5-6.

[14] See DRA Opening Brief, March 7, 2011, pp. 3-4.

4.4 Retail Customer Requirement Eliminated

> *20) Explain the next steps necessary to implement this provision [elimination of retail customer requirement], what modification to tariffs are needed to reflect this change, and what changes to the form contract might be required.*

DRA continues to support the broadening of eligible FiT customers and believes the Utilities are in the best position to identify all necessary changes to their tariffs to implement Section §399.20(b).[15]

4.5 Yearly Inspection and Maintenance Report

> *21) Parties are asked to comment on this recommendation [address yearly inspection & maintenance report requirement in 2012].*

DRA believes it is reasonable to address this issue at the beginning of 2012, as it is not a critical component of the implementation of this phase of the SB 32 program.

4.6 10-day Reporting Requirement of Request for Service under Tariff

> *22) Parties are asked to comment on this recommendation [address 10-day reporting requirement in 2011].*

DRA believes it is reasonable to address this issue by the end of 2011.

4.7 Publicly owned electric utilities

> *23) Identify any issues and explain why coordination [between IOUs and POUs] would be helpful. Identify any potential matters that the Commission may address relative to § 399.20 that may impact the implementation of § 387.6. One issue already identified in March 2011 briefs is the calculation of proportionate share of the 750 MW program cap.*

At this time DRA does not offer any specific recommendations on how the Utilities and POUs should coordinate their efforts to offer the tariff within their combined

[15] See DRA Opening Brief, March 7, 2011, p. 4.

and/or overlapping territories and SB 2 1X. DRA recommends that the allocation of the FiT capacity share to the POUs be based on the CEC's *California Energy Demand 2010-2020 Commission Adopted Forecast* report. DRA reserves the right to address this issue in reply comments.

4.8 Utility Discretion to Deny Tariff

> *24) Parties are asked to comment on this recommendation [address this issue in 2012]. Also, explain the existing procedure relied upon by electric utilities to deny tariff requests.*

As DRA stated in its March 7, 2011 opening brief, the Commission should expand the circumstances under which the Utilities can deny a tariff to include the situation in which an electrical corporation has already met its allocated cap.[16] DRA does not object to this issue being addressed at the beginning of 2012.

4.9 Tariff or Contract Termination Provisions

> *25) Parties are asked to comment on this recommendation [address this issue in 2012]. Also, explain the existing procedure relied upon by electric utilities to terminate contracts.*

DRA has no additional comments on the contract termination provisions issue and does not object to this issue being addressed at the beginning of 2012.

4.10 Expedited Interconnection Procedures

> *26) Parties are asked to comment on this recommendation [address this issue in 2012].*

DRA does not object to this issue being addressed at the beginning of 2012.

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[16] See DRA Opening Brief, March 7, 2011, p. 6.

4.11 Adjustments for Small Electric Utilities

27) Parties are asked to comment on this recommendation [address this issue in 2011].

DRA agrees with parties who advocate for allowing small electric utilities to voluntarily participate in the FiT program and believes this issue should be addressed before the end of 2011 as it will impact the proportionate share of capacity for each of the participating utilities.

4.12 Refunds of Other Incentives

28) Parties are asked to comment on this recommendation [address this issue in 2012].

DRA strongly recommends that the Commission consider the refund of incentives issue in the 2011 timeframe. In order to make SB 32 feasible and comply with elimination of the retail customer clause in §399.20, the Commission should have a mechanism in place for potential FiT customers to refund any ratepayer incentives received through other programs by the time the 750 MW phase of the program is scheduled to begin. Ratepayers in these areas, as well as potential transitioning FiT participants, will be placed at a disadvantage if such criteria is not in place before the commencement of the program.

III. CONCLUSION

For the reasons discussed above, the Commission should adopt DRA's recommendations contained herein. DRA emphasizes the following recommendations to the Commission:

1. Given the recent changes in the renewable energy market in California, DRA believes it is reasonable to transition from basing the tariff price of §399.20 from the current market-price referent (MPR) to a net energy metering surplus compensation rate as adopted by the Commission in D.11-06-016.

2. The Commission should consider the issue of refund of incentives in the 2011 timeframe instead of at the beginning of 2012. DRA believes it is critical to have this component of the program in place before the program commences in order to ensure fair pricing for all market participants and for the ratepayers who funded the incentives.

Respectfully submitted,

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