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)

SUSTAINABLE CONSERVATION AND GREEN POWER INSTITUTE COMMENTS TO SECTION 399.20 RULING JUNE 27, 2011

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I. Introduction

In accordance with the *Rules of Practice and Procedure* of the California Public Utilities Commission ("Commission") and the June 27, 2011 *Administrative Law Judge's Ruling Setting Forth Implementation Proposal for SB 32 and SB 2 1X Amendments to Section 399.20* ("Ruling"), Sustainable Conservation and the Green Power Institute ("Parties") submit these comments on Section 399.20 of the Public Utilities Code. Parties have long urged the Commission to implement Senate Bill 32, in order to create optimal conditions for a diversity of renewable distributed generation to contribute to California's clean energy and climate change goals. Sustainable Conservation's intervention before the Commission has always focused on deployment of farm scale, waste-based renewable energy technologies such as biogas and gasification technologies; Green Power Institute's intervention includes this focus, as well as solid-fuel biomass generators and renewables in general.

Below, Parties respond to the questions posed in the Ruling. Sustainable Conservation also incorporates by reference our Brief and Reply Brief on SB 32 implementation, submitted in R.08-08-009 in March 2011. We remind the Commission of the principles we recommended in those briefs to govern expansion of the feed-in tariff ("FIT"):

1. The program should be easy to access, understand, and implement.
2. The Commission must ensure that diverse resources are able to participate.
3. Pricing under this tariff must recognize the contributions of different renewable technologies (baseload vs. intermittent), as dictated in SB 32.
4. The Investor Owned Utilities should demonstrate ownership of the outcome and not just the process (i.e., success at overcoming hurdles to bringing new facilities on line).

II. Responses to Questions Posed in ALJ Ruling

To better conform to the instructions from the ALJ about the format of these comments, we are retaining the numbering used in the June 27, 2011 Ruling in this section.

3. Compliance with SB 2 1X

3.1 Definition of Market Price

1) Please respond in comments to the following questions: 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.

SB 32 created a FIT program for renewable generators up to 3 MW in size, with tariffs based on the "market price of electricity." The "market price of electricity" is an imprecise term, as the wholesale electricity market from which load serving entities procure energy consists of a variety of different kinds of products available in a range of prices, locations, terms, and conditions. Using the "market price of electricity" as the governing principle, and recent Rulings by the Federal Energy Regulatory Commission ("FERC"), the Commission would appear to have significant latitude with which to set tariff prices.

In fact, as is pointed out in the *ALJ's Ruling*, the statutory language pertaining to tariff pricing (California Public Utilities Code § 399.20(d)) that was entered into code by SB 32, and amended by SB 2 (1X), is identical to language that used to apply to the competitive RPS solicitation program (§ 399.15), but which was removed from the code by the same SB 2 (1X). The relevant language, which is repeated on page 3 of the *ALJ's Ruling*, provides a variety of options for determining a "market price of electricity." Dealing with the same language in the initial implementation of the RPS program in 2003, the Commission created the MPR. In no way does this mean that the Commission is obligated to adopt the MPR methodology in 2011 for

use in the § 399.20 program. The new language in § 399.20(d) sets forth a variety of considerations and options to be used in setting a tariff price, including looking at the cost of generation, and the value of different products. We urge the Commission to take a fresh look at the matter of determining a market price of electricity pertinent to setting the tariff rate for the § 399.20 program.

We believe that the Commission should authorize prices for the SB 32 program based on the cost structure for specific technologies. Looking at the list of considerations for calculating price outlined on p. 6 of the *Ruling*, several of those vary by technology or type of product. Among the considerations identified as mandatory, the long-term operating and fuel costs and current and anticipated environmental compliance costs vary by resource and technology. In addition, several of the considerations vary by type of product including: base-load, peaking, and as-available; contract length; time of delivery; and locational distribution circuit adder.

Indeed, some generators who may participate in the SB 32 program may be able to provide services to the utilities that go beyond the three categories listed in the statute: base-load, peaking, and as-available. For example, lagoon systems for dairy farms can be equipped with substantial amounts of gas storage at low cost, which allows operations that are not just simple baseload, as is typical for biogas generators, but baseload with the capability of providing load-following services if the appropriate incentives are included in the contract. Three rigid product categories may not be enough to cover the gamut of the services that eligible generators may be able to provide.

The Commission has already found that there is a difference in value for different electricity products. D.10-12-048 adopting the Renewable Auction Mechanism directs the utilities to solicit for electricity product "buckets" of baseload, peaking as-available, and non-

peaking as-available. Finding of Fact 24 of D.10-12-048 states: "Renewable products that are baseload, peaking as-available and non-peaking as-available provide different value to an IOU's electric portfolio." The RAM decision also recognized, in Finding of Fact 30: "Small RPS projects connecting to utility service territories incur none of the additional costs associated with some other forms of renewable generation."

The Commission also must recognize that there is value in having a diverse renewable resource portfolio that includes electricity from different fuel sources and generating facilities. To date, California's renewable portfolio is primarily solar and wind. Other renewable technologies, notably biomass, provide baseload renewable electricity. As indicated above, the Commission has recognized the different value that baseload, renewable, distributed generation electricity provides to the grid and to ratepayers even if it does not have the allure of wind and solar.

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.

There is certainly no obligation intended or implied in § 399.20 (d) for the Commission to base the tariff rate on the existing Market Price Referent ("MPR") methodology. Indeed, one of the intents of both SB 32 and SB 2 (1X) was to eliminate the use of the MPR as it pertains to various parts of the RPS program. The MPR is fossil based, has an often volatile price associated with natural gas and is based on large centralized plants. Section 399.20 (d) includes the same language from which the Commission developed the MPR methodology, but the language is more than sufficiently broad to support an entirely different approach to setting a tariff price. The market price of electricity that is used to set the tariff prices for § 399.20 contracts does **not** have to based on the MPR, and **should not** be based on the MPR.

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.

Question 3 appears to be a variant of Question 2. The price should not be based on the MPR, for reasons stated elsewhere.

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.

In our opinion, there is no benefit in continuing to use the MPR as the basis for setting the tariff rate for the § 399.20 program. Indeed, all evidence is to the contrary. The existing FIT programs in California with MPR-based pricing have produced few contracts, and fewer successful operating projects. The reason is simple: the MPR as currently constituted is inadequate to support these kinds of projects. A true application of ratepayer interests would promote a tariff rate that incorporates the public benefits into the price and instills vitality into the marketplace, while still being consistent with the principle of ratepayer indifference. We believe that a tariff rate that substantively promotes ratepayer interests **can** be constructed within the statutory language in § 399.20(d). That rate is not the MPR.

5) Under the current RPS program rules each annual RPS Solicitation triggers an update to the MPR values.[4] 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.

Our strong recommendation is to eliminate the use of the MPR in the § 399.20 program. Heeding our advice would obviate the need for recalculation of the MPR.

3.3 Additional Pricing Proposals

3.3.1 Technology-Specific Rates and Product-Specific Rates

6) Based on your definition of "market price of electricity," explain whether a technology-specific or product-specific proposal is a viable option for the § 399.20 program as updated by the SB 2 1X amendments.

Our definition of the market price of electricity explicitly recognizes that the marketplace is composed of a variety of types of products and services. Within this definition there is no doubt that technology-specific and/or product-specific tariffs are viable options that are consistent with the new § 399.20(d). The broad language of the statute explicitly allows considerations of existing procurement instruments, the costs of electricity generation, and the value of various products. Technology-specific and product-specific tariffs are fully consistent with the statutes, and their use would revitalize this currently under-subscribed program.

7) Explain the specific methodology and all calculations and data that would be required to implement the technology or product-specific rate that you propose.

As indicated above, Parties advocate policies that will lead to greater deployment of biogas and gasification technologies. This industry is in the early commercialization phase. There are two sources of publicly available price data that can inform Commission development of a feed-in tariff price for this suite of technologies: (1) a California Energy Commission ("CEC") funded study and (2) a State Water Resources Control Board study. We request the Commission take official notice of these studies, particularly the CEC study because it is based on biogas facilities that were actually built in California up to 2007 and reflects their actual costs.

(1) The October 2009 CEC study, *Economic Study of Bioenergy Production from Digesters at California Dairies*,[1] examined the experience of the ten Dairy Power Production Program ("DPPP") funded digester projects. The Study includes a detailed methodology and

[1] Cheremisinoff, Nicholas, Kathryn George, and Joseph Cohen. 2009. *Economic Study of Bioenergy Production From Digesters at California Dairies.* California Energy Commission, PIER Program. CEC-500-2009-058.

assessment of price of electricity needed to make these projects economically viable. In section 4.4, the study analyzed the price needed by each project to deliver a 17% internal rate of return ("IRR") and an investment to meet Water Board requirements (in a double-lined lagoon). It also removed grant dollars the projects may have received. In 2007 dollars, the average price needed was approximately 30 cents per kWh. In addition the price reported in the study excludes the cost in most cases of compliance with Air District's NOx requirements for the Central Valley.

(2) A May 2011 by the State Water Board, titled *Economic Feasibility of Dairy Manure Digesters and Co-Digestion Facilities in the Central Valley of California,*[2] reaches a similar conclusion: a price to 28 cents is required for manure-only digesters.

Sustainable Conservation continues to work with project developers to develop a more robust pricing model. We are mindful of the schedule established by the Commission and are working toward the reply comment and workshop dates. Importantly we believe that the cost of these facilities will come down over time as more are built and the technology improves. We are currently evaluating the cost structure of three of most recent biogas facilities, which may demonstrate this trend.

> *8) If applicable, identify what specific subset of proxy plants is appropriate for the calculation. An example of a Commission-adopted methodology for calculating technology-specific costs would be the MPR model, which calculates the proxy costs of building and operating a Combined Cycle Gas Turbine (CCGT) facility.*

Parties have had the opportunity to review an advance version of the comments being submitted by Fuel Cell Energy. We support Fuel Cell Energy's suggestion that the Commission convene a Working Group representing each technology. Each Working Group would put forward a proposed price that is representative of that technology category.

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[2] California Regional Water Quality Control Board, Central Valley Region, *Economic Feasibility Of Dairy Manure Digester And Co-Digester Facilities In The Central Valley Of California*, May 2011.

3.3.2 Market-Based Rate

9) In March 2011 briefs, Southern California Edison Company (SCE) suggested that price under § 399.20 be determined by competitive auction. Do you support this approach? Please explain. Discuss whether and how this approach is consistent with the provisions in § 399.20(f). Also explain the mechanisms of how a competitive auction would be used to determine the price (e.g., are projects paid as bid, paid the market clearing price, or paid another price point determined through an auction), and how, if at all, the auction would differ from the design of the Renewable Auction Mechanism in D.10-12-048.

A competitive auction mechanism is not appropriate for the small projects that are the intended beneficiaries of SB 32. The Commission was clear when it adopted RAM that the RAM is not the same as a feed-in tariff, stating on p. 1 of D.10-12-048: "RAM is distinct from a feed-in tariff as that term has traditionally been used."

Sustainable Conservation's analysis in comments on the Proposed Decision on the Renewable Auction Mechanism is relevant here:

> The RAM may be a viable option for large energy project developers whose primary business is development and operation of power plants, but for customers whose primary business is something else – such as farmers – the RAM bid process is too complex and does not offer sufficient price certainty to merit participation. These customers with the potential to install generating systems universally report that financing is already very hard to get and possible only by using the existing feed-in tariff price guarantee. They would have no chance of getting project financing under the RAM. If the Commission wants potential small, renewable distributed generation to succeed for farms, food processors, and small businesses, it must require utilities to offer a price certain based on the cost of the technology, not the cost of natural gas, as envisioned by SB 32.[3]

3.3.3 Rate Based on Power Purchase Agreements

10) Given that a significant number of RPS solicitations have occurred since this time, using your definition of the market price of electricity, explain whether a rate under § 399.20(d) should be based on RPS power purchase agreement prices. Parties supporting this methodology should identify what subset of power purchase agreements is appropriate for the calculation, whether the price should be the weighted average of PPA prices or some other price point, and provide specific recommendations and calculations, where appropriate and necessary to

[3] Sustainable Conservation, *Comments of Sustainable Conservation on Proposed Decision Adopting the Renewable Auction Mechanism*, September 27, 2010, pp. 9-10, in R.08-08-009.

implement such a methodology. Lastly, parties should articulate if there should be one rate or multiple rates. If parties suggest multiple rates, parties should define what the multiple rates should be and how they should be derived.

Specific to biogas technology, there are very few power purchase agreements ("PPAs") in place for biogas facilities, certainly not in the case of dairy biogas. As such, we need to rely on facilities that do not currently operate under a PPA to estimate the cost structure of this technology category. Recently there has been some effort to evaluate the cost structure of biogas projects to determine an appropriate price for these technologies. We are currently working with project developers to assess what an appropriate price would be given the current cost structure of recent facilities.

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

Parties refer the Commission to our response to Question 7.

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.

As discussed above there are both public and confidential data sources. The most thorough public source is the October 2009 CEC study.

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 Commission likely will need to look at three adjustment factors to the price over the life of the program: an annual inflation adjustment, the increasing cost of O&M as the facility ages, and fuel cost. Parties concur with Fuel Cell Energy (in its advance draft of these opening comments) that the Commission must retain its discretion to adjust prices downward or upward within each technology-specific price category in response to unanticipated developments in the program.

3.5 Ratepayer Indifference

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.

In D.09-12-042, the Commission addressed the issue of ratepayer indifference to, in that case, the tariff developed pursuant to AB 1613. The same reasoning can be applied here:

> In light of these considerations, we find that customer indifference under AB 1613 would not be achieved if the price paid under the program only reflected the market price of power. As discussed, since customers who are not utilizing the eligible CHP system will receive environmental and locational benefits from these systems, the price paid for power should also include the costs to obtain these benefits.[4]

3.6 FERC Order 134

15) 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. Please indicate how those positions have changed, if at all.

Sustainable Conservation does not at this time offer additional comments beyond those provided in our March 2011 briefs. Particularly:

- FERC now recognizes the importance of allowing states to establish avoided costs that reflect state policies, for example, greenhouse gas emission adders and regulatory compliance. In the January 2011 denial of the utilities' request for rehearing, FERC is

[4] D.09-12-042, p. 17.

clear that States determine what costs a utility is avoiding when it purchases from a qualifying facility, and that States can require utilities to purchase capacity.[5]

- States can establish multi-tiered avoided cost structures that reflect a range of avoided costs depending on the resources the utility is avoiding having to build or purchase.[6]

4 Compliance with SB 32

16) 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. Parties are requested to comment on this proposal.

Parties appreciate that the Commission is trying, with the suggestion to bifurcate issues, to address more "pressing" issues this year. However, in the context of the tariff, it is probably more efficient to address all issues concurrently. This is how the Commission developed the current feed-in tariff in 2007, as directed by Assembly Bill 1969. Of particular import to Sustainable Conservation, and as described below and in the *Petition to Modify D.07-07-027* submitted in this docket and R.08-08-009 on June 27, 2011, the Commission must correct the current problems with interconnection. When both price and interconnection are properly established and operational, we expect biogas projects will come online. Customer generators (i.e., farmers), developers, and financiers have a price that supports their investment. And they must be able to interconnect and a timely and clear manner with an understanding of the contract terms, pricing, and administrative steps (such as interconnection) before they will proceed.

4.1 Increase Size of Eligible Facility to 3 MW

17) This ruling proposes to implement the 3 MW provision by end of 2011. 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.

[5] FERC, *Order Denying Rehearing*, January 20, 2011, Paragraphs 30, 32..
[6] FERC, Dockets EL10-64-001 and EL10-66-001, *Order Granting Clarification and Dismissing Rehearing,* October 2010, paragraph 29.

As indicated above, one of the principles that should govern the Commission's implementation of SB 32 is: ensure that diverse resources are able to participate. We expand on this below.

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? This ruling proposes to implement this provision by end of 2011.

As we stated in our March 2011 brief, as the Commission looks at how to calculate the proportionate share, it should recognize that certain technologies are currently underrepresented in the utilities' renewable portfolio, and that these technologies provide specific benefits that other technologies that are represented in greater proportion mostly do not. The Commission should reserve within the SB 32 cap a recommended 150 MW of capacity for baseload renewable biomass resources. Within this baseload renewable resource reservation, the Commission should ensure that various generator categories have the opportunity to participate. These should include agricultural feedstock (both livestock and non-livestock) facilities, municipal waste feedstock facilities, and food processing facilities. All have access to renewable fuel sources that can be used, for example, in biogas digesters and gasification electricity generators.

4.3 Separate Tariffs

19) Based on the language of § 399.20, it appears reasonable to direct electric corporations to consolidate the two rates schedules. Consolidation of tariffs may decrease transaction costs by simplifying the administration of the program. This ruling proposes to implement this provision by end of 2011. Explain the next steps necessary to implement this request.

Sustainable Conservation supported this action in our March 2011 brief. Our position has not changed. The process outlined by the Commission for the utilities to file tariffs, and for workshops at the end of August, should provide a sufficiently robust process, particularly if the Commission employs alternative dispute resolution practices in the facilitation of the workshop.

4.4 Retail Customer Requirement Eliminated

20) § 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. This ruling proposes that the Commission implement this provision by end of 2011. Explain the next steps necessary to implement this provision, what modification to tariffs are needed to reflect this change, and what changes to the form contract might be required.

As indicated above, the Commission must ensure that no one technology category or vendor dominates the portfolio under the SB 32 or related programs. Large or well financed technology categories in particular should not be able to "muscle out" emerging technologies.

4.5 Yearly Inspection and Maintenance Report

21) SB 32 added the requirement to § 399.20 that the "owner of the electric generation facility receiving a tariff pursuant to this section shall provide an inspection and maintenance report to the electrical corporation at least once every other year." This requirement was added at subsection (p) of § 399.20. SB 2 1X did not modify this requirement. This ruling proposes that the Commission not implement this provision by end of 2011 and, to instead, address this matter at the beginning of 2012. Parties are asked to comment on this recommendation.

Sustainable Conservation does not offer additional comments on this question at this time, beyond those offered in our March 2011 brief. The contents of the report will be important. This could otherwise be a time-consuming and expensive exercise with little or no public benefit.

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

22) 10 day reporting requirement: This ruling proposes to implement this provision by end of 2011. Parties are asked to comment on this recommendation. This implementation will primarily rely on the reporting format that the Commission already requires, with the specific changes to reflect SB 32. This

information is: Project Name, Status (e.g., Operational, delayed), Capacity (MW), Expected GWh/yr, Technology, Price ($/MWh), Vintage (e.g., existing, new), Term (years), Location (City), Contract Execution Date, Online Date/Contracted Delivery Date, and Achievement of the Commercial Delivery Date with 18 months (yes or no).

We reiterate here our earlier recommendations for reporting requirements related to interconnection, offered initially in our March 2011 briefs. Given the major impediment posed by interconnection, the Commission must gather information about interconnection status. Toward that end, the Commission should require the utilities to submit a semi-annual report on the number of interconnection requests, by technology type and size, location, and date request was initially submitted. The report also should indicate any project for which an interconnection request has been pending for more than six months and identify what the utility is doing to complete the interconnection request. If the utility is requiring further study, it should indicate the purpose of those studies and the estimated cost to the customer of completing them. Most importantly it should track the barriers customers experience in trying to interconnect with the utility and identify what is being done to surmount them. We have found that the utilities do not have good internal coordination and that their requirements change with assigned personnel, among many other problems the utilities have in processing applications.

4.7 Publicly Owned Electric Utilities

23) It is reasonable to anticipate that certain issues to be resolved in implementing SB 32 and SB 2 1X for investor owned utilities may benefit from coordination with local publicly owned electric utilities. This ruling anticipates addressing these issues by the end of 2011. Identify any issues and explain why coordination 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.

Sustainable Conservation does not offer additional comments on this question at this time. The publicly owned utilities seem to do a much better job with processing interconnection

applications and are more helpful to developers. The investor-owned utilities may be able to take a lesson from what they are doing right.

4.8 Utility Discretion to Deny Tariff

24) This ruling proposes to not implement this provision by end of 2011. This issue will be addressed at the beginning of 2012. Parties are asked to comment on this recommendation. Also, explain the existing procedure relied upon by electric utilities to deny tariff requests.

Sustainable Conservation recommended in our March 2011 brief that Rule 21 be the standard under which all interconnection at the distribution level occur. Rule 21 includes a dispute resolution provision, governed by the Commission. While we hope dispute resolution will not be necessary, the Commission must anticipate that it may.

4.9 Tariff or Contract Termination Provision

25) This ruling proposes to not implement this provision by end of 2011. This issue will be addressed at the beginning of 2012. Parties are asked to comment on this recommendation. Also, explain the existing procedure relied upon by electric utilities to terminate contracts.

In our March 2011 brief, Sustainable Conservation stated: "The tariff must be offered in 10, 15, or 20 year increments. There are no other circumstances in SB 32 that allow contract termination." Our position has not changed.

4.10 Expedited Interconnection Procedures

26) This ruling proposes to not implement this provision by end of 2011. This issue will be addressed at the beginning of 2012. Parties are asked to comment on this recommendation.

Sustainable Conservation has long urged the Commission to address interconnection on an expedited basis. The problems posed by interconnection are too great to wait until 2012. On June 27, 2011, Sustainable Conservation filed a Petition to Modify D.07-07-027 specifically requesting the Commission take immediate action to enforce its jurisdiction over interconnection

at the distribution level.[7] At the July 11, 2011, Prehearing Conference, many parties echoed their concern that interconnection must be a priority, including CalSEIA, the Sierra Club of California, the Agricultural Energy Consumers Association, and the California Farm Bureau Federation. Southern California Edison also agreed that interconnection must be addressed with the other pieces of the SB 32 program. This rare agreement by diverse parties should be heeded.

4.11 Adjustments for Small Electric Utilities

27) This ruling anticipates addressing these issues by the end of 2011. Parties are asked to comment on this recommendation.

Sustainable Conservation does not offer additional comments on this question at this time.

4.12 Refunds of Other Incentives

28) Refunding incentives from other programs. This ruling proposes not to implement this provision by end of 2011. This issue will be addressed at the beginning of 2012. Parties are asked to comment on this recommendation.

In March 2011 briefs Sustainable Conservation suggested the Commission establish a statute of limitations on the refund requirement for those who participated in the Self Generation Incentive Program. Specifically, if a project received the funds more than 4 years ago, no refund should be required. Ratepayers have received the benefit of electricity from these renewable projects for many years, and they should not now be penalized for taking advantage of a new tariff opportunity.

III. Conclusion

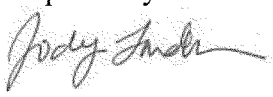
The Commission has an opportunity this year to implement the modifications directed nearly two years ago in SB 32. The Commission must follow the Legislature's direction to address the pricing and interconnection issues that currently create barriers for small distributed

[7] *Petition of Sustainable Conservation for Modification of D.07-07-027: Opinion Adopting Tariffs and Standard Contracts for Water, Wastewater and Other Customers to Sell Electricity Generated from RPS-Eligible Renewable Resources to Electrical Corporations*, June 29, 2011, in CPUC Docket R.11-05-005.

generation. As the Commission moves forward, it should establish policies that prioritize a diverse renewable resource portfolio, with prices specific to the different technologies that can help California achieve its energy and environmental goals.

Dated: July 21, 2011

Respectfully submitted,



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For SUSTAINABLE CONSERVATION

Verification

I am the representative for the applicant herein; said applicant is absent from the County of Alameda, California, where I have my office, and I make this verification for said applicant for that reason; the statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

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

Executed July 21, 2011, at Oakland, California.

Jody London
FOR Sustainable Conservation