BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

COMMENTS OF SIERRA CLUB CALIFORNIA ON THE ADMINISTRATIVE LAW JUDGE'S RULING SETTING FORTH IMPLEMENTATION PROPOSAL FOR SB 32 AND SB 2 1X AMENDMENTS TO SECTION 399.20

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1. Introduction

Sierra Club California respectfully submits the following Comments in accordance with 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‖). In the ALJ Ruling, ALJ DeAngelis requested that parties comment on a series of questions, and the goal of implementing parts of the feed-in tariff program in 2011 and in 2012.

Sierra Club California is comprised of more than 150,000 members and ratepayers throughout California. Sierra Club California supports successful implementation of effective feed-in tariffs that can help meet California's targets for renewable energy.

2. Implementation Goals

Feed-in tariffs offer the proven potential for fast integration of renewable energy, reduced project transaction costs, and increased opportunity for developing small renewable energy projects. In Sierra Club California's Opening Comments in R.08-08-009, Sierra Club urged for (1) prices that are effective for stimulating the broad growth of renewable distributed generation, (2) increasing the project capacity limit to 20 megawatts, and (3) for California to develop much more distributed generation than the targets set by SB 32. While it is most important to get this program established by setting prices and developing pro forma contracts as much as practicable in 2011, the expansion and further development of this program should be considered in 2012. This may involve an interim decision, followed by a more comprehensive and long-term decision.

3. Implementation of SB 2 1X

3.1 Market Price is Best Defined as Avoided Cost

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.

A. Market Price, as Defined by Section 399.20(d)(2), Aligns with the Avoided Cost Definition Established by the Federal Energy Regulatory Commission.

SB X1 2 changed a major factor for the price in the standard tariff from the—market price referent‖ to—market price.‖[1] The Commission is directed consider factors such as—the long-term market price of electricity for fixed price contracts,‖ the—long-term ownership, operating, and fixed-price fuel costs,‖ and—the value of different electricity products including baseload, peaking, and as-available electricity.‖[2] The payment rate may also be adjusted to reflect the

[1] Public Utilities Code Section 399.20(d)(2).
[2] Id.

value based on time-of-delivery,[3] must include environmental compliance costs,[4] and the Commission shall consider and may establish a value for the locational benefits of distribution that offsets peak demand capacity costs.[5] SB 32 also states the Legislature's intent to prioritize renewable generation that:―Is strategically located and interconnected to the electrical transmission and distribution grid in a manner that optimizes the deliverability of electricity generated at the facility to load centers.‖[6]

These factors describe characteristics of an―avoided cost‖ methodology,[7] because they describe the long-term costs of fixed price and variable price electricity contracts, and the cost savings from avoided peak generation and distribution. The Federal Energy Regulatory Commission (―FERC‖) considers these factors in their implementation of―avoided cost,‖ under the Public Utility Regulatory Policies Act (―PURPA‖) including―(1) the utility's system cost data; (2) the terms of any contract including the duration of the obligation; (3) the availability of capacity or energy from a QF during the system daily and seasonal peak periods; (4) the relationship of the availability of energy or capacity from the QF to the ability of the electric utility to avoid costs; and (5) the costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from the QF.‖[8]

While States have considerable latitude in developing methodologies to calculate the ―avoided cost‖ limits of PURPA,[9] the new Public Utilities Code definition of market price now more closely aligns with the factors considered to be avoided cost. Sierra Club California recommends that the Commission first define―market price‖ as―avoided cost‖ and in doing so

[3] Public Utilities Code Section 399.20(d)(2).
[4] Public Utilities Code Section 399.20(d)(1).
[5] Public Utilities Code Section 399.20(e).
[6] Public Utilities Code Section 399.20(b)(3).
[7] See also 16 U.S.C. Section 824a-3(b)(2) (PURPA definition of avoided cost); 133 FERC 61,059 (Issued October 21, 2010).
[8] 18 C.F.R. Section 292.304(e).
[9] 133 FERC 61,059 at para. 24.

to reference the recent FERC rulings clarifying State discretion in defining avoided costs.[10] By adopting a definition of avoided cost, the Commission achieves the greatest legal certainty that the Commission is in compliance with FERC's Order.

B. Market Price Includes Subsets Based on Differentiated Renewable Energy Technologies for Solar PV, Wind, Biogas, and Additional Technologies.

States can establish multi-tiered avoided cost structures that reflect a range of avoided costs based on the specific resources the utility is required to purchase. FERC has held that ―permitting states to set a utility's avoided costs based on all sources able to sell to that utility means that where a state requires a utility to procure a certain percentage of energy from generators with certain characteristics, generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement requirement.‖[11] In addition, FERC held that ―should California choose to do so, implementation of a multi-tiered avoided cost rate structure can be consistent with the avoided cost rate requirements set forth in PURPA and the Commission's regulations in that such a cost structure would reflect the costs a utility would avoid.‖[12] Therefore, California may establish requirements for differentiated generation technologies, and set avoided costs based on these differentiated technologies.

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[10] 134 FERC 61,044 (CPUC Docket No. EL10-64-002 issued January 20, 2011); 133 FERC 61,059 (CPUC Docket No. EL10-64-001 issued October 21, 2010)
[11] 133 FERC 61,059 at para. 29.
[12] 134 FERC 61,044 at para. 28.

The Commission has broad authority granted by the California Constitution to regulate public utilities,[13] and is not precluded from setting procurement targets based on differentiated renewables technologies. Sierra Club California recommends setting such procurement targets differentiated by technologies including solar, wind, biogas, and other renewable resources. Sierra Club California also recommends either: (a) further differentiating such targets by project size and application characteristics, or (b) applying a cost containment mechanism that limits the tariff price to a reasonable cost including reasonable rate of return. This approach is recommended not only to establish a clear avoided cost, but to encourage diversity of energy resources. This diversity helps to promote a balanced portfolio and renewable resources that balance generation and grid operations, and cost containment.

Section 399.20 directs the Commission to set prices taking into consideration―the value of different electricity products *including* baseload, peaking, and as-available electricity.‖[14] This strongly suggests that prices should be differentiated at least by these three generation qualities of generation, and encourages further differentiation of tariffs for generation technologies based on type and project size. To do otherwise will likely overpay or underpay for different generation products. This approach will allow renewable generation to be purchased at the appropriate price for each category and prevent windfall profits resulting from rates that exceed the cost of production. This approach will also help promote a balanced renewables portfolio. It is in the interest of California electricity ratepayers to have an appropriate diversity of renewable generation types to include baseload (e.g. biomass, biogas and geothermal), peaking (e.g. solar PV) and as-available (e.g. wind). This diversity can allow the generation characteristics of these various technologies to complement each other such as wind and solar

[13] Cal. Const. Art. XII, §6.
[14] Section 399.20(d)(2)(C). Emphasis added.

while providing a portion of baseload to support intermittent generation. Diversification of energy resources will also increase electricity security and reliability.

Once the Commission has established procurement targets based on differentiated renewables technologies, the Commission should set avoided cost rates based on each of these market segments differentiated by technology. Please refer to our response to Question 6 for more detail on developing technology-specific prices.

C. Sierra Club California Proposed Allocation by Technology and Size

The following table is illustrative of how to allocate specific capacity amounts to each technology and project size:

Technology & Size Allocations	Size Range	Capacity	Capacity Factor	Annual Generation	Program Share of Generation	Technology Subtotal Share
Solar PV		kW	%	kWh	% of kWh	% of kWh
Residential	1 to 10	100,000	16.6%	145,000,000	12.4%	
Commercial	10 to 100	100,000	17.7%	155,000,000	13.3%	
Industrial	100 to 1000	100,000	18.8%	165,000,000	14.1%	
Subutility	1000 to 5,000	100,000	20.0%	175,000,000	15.0%	
Wind						54.8%
Small Wind	1 to 150	10,000	12.0%	10,500,000	0.9%	
Community Scale Wind	150 to 1500	30,000	16.6%	43,500,000	3.7%	
Subutility Wind	1500 to 5,000	50,000	25.1%	110,000,000	9.4%	
Biogas						14.0%
Small Biogas	1 to 150	10,000	57.1%	50,000,000	4.3%	
Commercial Biogas	150 to 1500	10,000	68.5%	60,000,000	5.1%	
Subutility Biogas	1500 to 5,000	20,000	79.9%	140,000,000	12.0%	
Geothermal						21.4%
Small DG Geothermal	less than 1 MW	10,000	60.0%	52,560,000	4.5%	
Large DG Geothermal	1 MW to 5 MW	10,000	70.0%	61,320,000	5.3%	
						9.8%
Total		550,000		1,167,880,000		

The table attempts to provide a diverse portfolio that would provide some peak power (solar), some baseload (biogas and geothermal), and some intermittent / as-available generation (wind). This portfolio approach is intended, by specifying exact amounts of capacity for each technology and project size range for each price of feed-in tariff, to create a framework for benchmarking the—avoided cost‖ into the cost of that specific technology and size, within the meaning of FERC's ruling on avoided cost.

A further feature of a specified matrix of technologies and sizes is that once a feed-in tariff price schedule is matched to each item on the list, the result is a relatively constrained cost for the entire program. Through applying balancing portions of each project size range and technology, the cost of the portfolio as a whole, and the combined cost for each technology type, can be calibrated. Smaller and more expensive projects, when measured per kilowatt-hour generated, are carefully balanced and offset by larger projects that have a lower cost per kilowatt-hour. This is designed such that the average cost per kilowatt-hour is only modestly increased relative to what the cost would be if only the lower cost renewables in each technology were built. Furthermore, this portfolio approach prevents all of the projects from being exclusively solar PV, by balancing these projects with lower cost technologies.

In summary, a determinate portfolio approach that includes a range of technologies and sizes can achieve (1) a diverse portfolio that provides a designed mix of baseload, intermittent and peaking services, thus having specific grid benefits, and (2) wide democratic participation in the program, while limiting the cost effect of this feature. Sierra Club California recommends a capacity allocation similar the proposal contained in these comments.

D. The Avoided Cost of Procurement of the 33% Renewables Portfolio Standard Resources is an Alternate Measure of Avoided Cost.

An alternative method of determining market price is to calculate the avoided cost relative to a scenario that includes the costs associated with procurement of the energy portfolio, including procurement of the 33% renewables portfolio standard resources. This method, while less preferred to setting avoided cost based on specific technologies, would allow the Commission to determine market price and avoided cost based on anticipated costs associated with procurement of the energy portfolio, including the costs of RPS compliance. This is in contrast to the option of continued reliance on the MPR, which is based on the long-term price of natural gas and does not relate to the avoided cost of renewable energy.

The state already mandates that 33 percent of electricity must come from renewable generation by 2020. Thus, distributed generation projects represent a way to comply with that renewable energy requirement that might otherwise be met with large central station renewables. We propose that it is reasonable, as an alternative methodology, to consider the avoided cost of distributed generation to be the cost of energy from a comparable amount of energy from central station renewable facilities, plus the locational benefits of the distributed generation. Thus, the avoided cost of distributed wind can be defined as the cost of wind power from a central wind plant, and should include the added cost of transmission and line losses to the delivery point. RETI has prepared a table of such projects, which clearly shows that there is no single—avoided cost‖, but rather that central wind, solar, geothermal, etc., energy resources have a wide range of cost for different potential projects.

Broadly, it is possible to take a reasonable range of cost of energy from such central station projects and make assumptions similar to the LTPP RPS Cost Calculator that projects will be selected in priority order based upon cost and other primary criteria, and the cost range of such selected projects, or model proxy central renewable energy projects, can serve as avoided cost for distributed renewable energy in a similar manner as the former MPR created a proxy cost for natural gas power. Indeed, the avoided cost calculation will likely be simpler than the MPR, and may draw upon the existing RETI database for extensive reference source data to derive a baseline cost for a variety of renewable technologies.

Thus, what we propose in this alternate avoided cost concept is that the avoided cost would be derived from the range of reasonable costs for energy from large scale renewable projects, with the adders for transmission and line losses. This might be derived from the RETI database, and apply basic principles that have already been implemented for the RPS Calculator—including project selection by cost and other specified criteria such as environmental and project viability. Again, this is not something that needs to be done anew; the RPS calculator and the RETI database already has the foundation of a selection methodology built in. A formula could be constructed based upon the RETI model, that would take the selected projects of each technology type, add up the cost of energy for all selected projects of a single technology combined, and divide by the generation from all the selected projects of a single technology combined. The result would be a single, simple cost rate per kilowatt-hours. The projects could be selected based upon criteria already set up in one of the scenarios, such as the Trajectory Scenario.

As suggested in the discussion about allocation to technologies and sizes, the avoided cost in this case would be compared not to each single project size category in the feed-in tariff tables—which was a particular weakness of the MPR— but rather to the whole portfolio blend, either for the full range of project sizes for each technology or for the technologies combined into the particular designed blend in the portfolio as a whole. The inputs of specific amount of capacity, capacity factor and feed-in tariff price, will result in a specific cost of energy for each technology and for the portfolio as a whole. This calculation is quite simple—taking the cost of generation of each technology type, adding up the total cost, and dividing by the amount generated by that all size projects using that technology. The prices for renewable distributed generation can then be compared to the cost of energy from ―conventional‖ central station renewables.

The simplest and most direct avoided cost for distributed generation is not central station renewables, but the proxy model cost of energy from the distributed generation itself.
Again, this is no different in principle from constructing a proxy natural gas plant, except that in this case the avoided cost would be measured apples to apples—since the proxy is the same technology and size as the technology and size that is being measured for avoided cost. This method, of measuring the avoided cost of distributed generation using a distributed generation cost model, would be our preferred approach. A second best would be to take the proxy cost of central renewables that are comparable to the distributed generation technology, although obviously not of the same size.

3.2 The MPR was Repealed from Statute, is based on Avoided Natural Gas Procurement, Fails to Consider Significant Cost Factors, and is Unrelated to Avoided Costs of Renewable Energy Procurement, but if this is chosen the Commission Should Include Adders for Time of Delivery, Locational Benefits, and Avoided Transmission and Distribution Costs.

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.

As explained in the response to Question 1, market price should first be based on avoided cost, set at the rate of differentiated technology costs. An alternative avoided cost method can be based on the cost of the procurement of the energy portfolio, including the 33% RPS. Sierra Club California strongly prefers either of these two methods (differentiated technologies or portfolio cost) rather than continued use of the market price referent (―MPR‖). Avoided cost may in part include cost factors that are also included in the MPR, however the MPR does not adequately measure the avoided costs of long-term natural gas procurement.

The Legislature, in enacting SB 2 1X, expressly deleted the market price referent from the RPS statute, and established new provisions in Section 399.20 for the commission to establish a methodology for ―market price.‖ The Legislative Digest of SB 2 1X stated that the legislation ―would delete the existing market price referent provisions.‖ The Legislature simultaneously established a new cost containment mechanism that is independent of the MPR. The Senate Energy, Utilities, and Communications committee analysis noted that SB 2 1X market price language ―changed the basis of the calculation of the contract payment‖ away from the MPR.[15] The Assembly Natural Resources committee analysis stated that SB 2 1X amended Section 399.20 ―to account for this bill's *repeal of the MPR*, by requiring the PUC to set a *similar* market price specifically for purposes of the feed-in tariff statute.‖[16] The calculations contained within the MPR are a portion of natural gas avoided costs, but market price is more expansive than the MPR, and by definition is inclusive of all avoided costs.

While some elements of market price have been quantified within the market price referent, the market price referent is inappropriate as the sole basis of market price, because the

[15] California State Senate Energy, Utilities, and Communications Committee Bill Analysis, February 14, 2011 at 10.
[16] California State Assembly Natural Resources Committee Bill Analysis, March 4, 2011 at 6. Emphasis added

legislature expressly deleted the market price referent from §399.20, and use of the MPR would be inadequate to measure market price and avoided cost. Should the Commission choose to continue to rely on the MPR as a portion of determining avoided cost, the Commission should carry over the calculated avoided costs contained within the MPR, improve and update these calculations to correctly reflect the avoided cost of long-term natural gas electricity, and in determining market price and avoided cost, also include values for time of delivery and locational benefits of avoided transmission and distribution costs.

The MPR created a synthetic model for the cost of energy from a base load natural gas plant and used it as a measuring stick to determine the acceptable value of various renewable energy resources. In this way, the fictional model of a natural gas plant became defined as the avoided cost for renewable energy.

The MPR had many drawbacks, but perhaps the largest derived from its attempt to rely on the price of the natural gas commodity. The MPR was based in significant part upon a forecast of what natural gas prices would be over a 10 year, 15 year, 20 year and 25 year period in the future. There is in fact no way to know in advance what natural gas prices will be in the next 10 to 25 years; thus this feature of the MPR is simply a guess. This forecast guess of how much future natural gas prices would be was heavily based upon the current prices for natural gas at the time the forecast was made. This creates a bias in the forecast that increases and decreases the forecast based upon prices in the recent past. In psychology this effect is referred to as―anchor bias,‖ in which a guess is heavily influenced by the data that has been most recently viewed.

In years when natural gas prices are high, the estimated future prices of natural gas in the MPR would be higher than in years when natural gas prices were low. A 20-year wind contract proposed in 2009, in a year after natural gas prices were high, would be imagined to have a higher avoided cost—and thus a higher value—than exactly the same wind project proposal in a year when natural gas prices were low. Yet, the fact that natural gas prices are high or are low in 2008 has almost no determinative value for what natural gas would cost in 2015, 2020 or 2030. Thus, the MPR was a fictional avoided cost in that it cannot tell us what the real cost of natural gas power would be in 2020. If it turns out the price of natural gas is different than what the model said in the year the wind contract was signed, then we would contend that the calculated avoided cost from the MPR was in error. In other words, the MPR is a sophisticated guess, but only a guess, of what the long-term avoided cost based upon a natural gas plant would in fact be.

A second problem with the MPR is that it assumes that a natural gas plant can be reasonably assumed to be the basis for calculating the avoided cost for renewable energy. On the contrary, we propose that the MPR cannot be the avoided cost, unless in fact the cost of the renewable energy is avoidable. The cost of renewable energy *is not avoidable*, as there is a statutory mandate to purchase renewable energy. In such a case there is no question of buying natural gas power instead of renewable energy. There will only be a question of what form of renewable energy to purchase. This reasoning is in accord with FERC about the meaning of an avoided cost, as discussed in the response to Question 1, and leads to the conclusion that the MPR is an inappropriate basis for avoided costs because it does not reference a scenario where California has procured 33 percent of energy resources from renewables.

A third problem with the MPR is that it did not apply to power from a natural gas plant in the same way it applied to renewable energy. The renewable energy project had to compete with the fictional cost of power from a model natural gas plant. However, a natural gas plant does not fully assume the risk of future price increases in natural gas; that is generally a ―pass through‖

charge. There is no such comparable pass through on wind power contracts. One could argue that the MPR embodied this price risk by assuming all future natural gas purchases are hedged. However, it is not clear if the assumed hedge value is valid, since we don't know the future price of natural gas, especially over a 15 to 25 year period in the future.

Repairing these problems beyond a certain level is not likely feasible; i.e., an MPR would be very difficult to deconstruct into a cost of technology based tariff. However, value adders for time of delivery and locational benefits of avoided transmission and distribution costs can synthetically create a differentiated set of tariffs for baseload, peak and intermittent energy supplies, which then translate to groups of technologies. So, geothermal and biogas would apply to the baseload tariff, solar would apply to the peak tariff, and wind would be valued by the distribution of time of delivery.

The Commission should support providing different capacity values that relate to avoided cost. This might incentivize developers to provide services that enhance reliable capacity, such as adding storage or other potential for backup power. A crucial element in improving upon the MPR-type approach is to include locational value, including avoided transmission and distribution costs. However, these avoided costs can vary widely in different areas, and can depend on what specific costs are avoided. For instance, if distributed generation could have avoided construction of the Sunrise Powerlink, its effective load carrying capacity value would reach $1,900 per kilowatt, which was the cost of that particular line. On the other hand, if the line is built, then that capacity cost cannot be avoided. The actual construction or decision not to construct alternative infrastructure can radically affect the locational value of distributed renewables. Time of day factors can make the tariff structure quite complex; creating a matrix of dozens of prices for each year. Thus, efforts to—repair‖ the MPR approach can be as complex as cost-based approaches, especially if the aim is to provide prices that are meaningful for at least some types of small scale distributed renewable energy projects.

For these reasons, Sierra Club California recommends avoided costs that are benchmarked against differentiated renewable technologies, or procurement of the energy portfolio including the RPS, rather than continued reliance 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.

As stated in responses to Questions 1 and 2, the price for electricity purchased under § 399.20(d) should first be based on avoided cost. Should the Commission continue to rely on the MPR, or an updated and corrected calculation of the MPR, then avoided cost would be inclusive of the adders suggested by parties in the March 2011 briefs. This umbrella framework is recommended because the FERC rulings clarify the ability of states to establish differentiated tariffs using avoided cost. These rulings were very recent as of the March 2011 briefs, and this opportunity for Comments by parties is better informed regarding avoided cost as the most appropriate overall framework for market price at this time.

If the MPR calculations continue to be a portion of market price, then Sierra Club California strongly supports new adders to be included within avoided cost, as included in the responses to Question 1 and 2, and discussed by parties in the March 2011 briefs. These adders include time of delivery, locational benefits, environmental compliance costs, and avoided transmission and distribution costs. The research prepared by the California Solar Energy

Industries Association (CalSEIA),[17] along with the discussion presented in the Opening Briefs of CalSEIA, Sierra Club California, Solar Alliance, and Clean Coalition provide a strong justification for the inclusion of these adders, and a finding that these values are based on avoided costs and by definition satisfy ratepayer indifference.

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.

Please refer to the response to Question 2. The MPR is no longer appropriate to use as a framework price upon which to build feed-in tariffs for renewable energy, and the legislature has deleted it from the law. Additionally, FERC has ruled that if a state sets a requirement for a new category of generation with certain requirements, that category becomes the new pool of resources in competition and basis for avoided cost. The CPUC should begin with an avoided cost definition of market price, include calculations that have been included within the MPR, include values for time of delivery and locational benefits, and further differentiate those resources by resource type and project size, to determine most appropriate prices and contain costs.

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

[17] http://calseia.org/wp-content/uploads/2010/05/pv-above-mpr-methodology-final-20100423.pdf.

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.

As noted in Questions 2, 3, and 4, the MPR is no longer appropriate as the primary basis for setting market price. To the extent that the calculations in the 2011 MPR process updates avoided cost factors, these findings could be included as line items within avoided cost.

Updates to all factors affecting avoided cost may be appropriate every other year. For technologies with declining prices such as solar PV, a built-in digression schedule can be effective toward encouraging cost containment and cost reductions as technologies are brought to scale. Alternatively, the CPUC could re-set the rate annually, so long as sufficient notice of about a year is provided to generators, and so long as the methodology is reasonably consistent to as to provide long term stability of policy to the sector. Should a new breakthrough technology emerge, or a significant change in cost structure arise in the marketplace for one or more technologies, the CPUC should reserve the right to conduct a comprehensive review of the rates at the ordinary time for re-setting market price.

3.3 Sierra Club California Recommends Technology-Specific Rates, Differentiated by Size and Other Cost-Based Factors.

3.3.1 Technology-Specific Rate and Product-Specific Rate

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.

As discussed in the response to Question 1, setting technology-specific rates are highly recommended because (1) establishing procurement targets for specific technologies and products helps promote a balanced portfolio, with benefits to grid operations and integration of intermittent renewable energy resources, and (2) setting and limiting the tariff price at the actual cost of production helps to promote a cost-effective feed-in tariff program that is cost-contained because it avoids the potential for windfall profits for less expensive renewable technologies. It is in the interest of the state, its electricity consumers and ratepayers to have an appropriate diversity of renewable generation types to include baseload (e.g. biomass, biogas and geothermal), peaking (e.g. solar PV) and as-available (e.g. wind). Diversification of energy resources will also increase electricity security and reliability. Diversity in the renewables portfolio can allow the generation characteristics of these various technologies to complement each other such as wind and solar, while providing a portion of baseload to support intermittent generation.

Pricing should be based upon avoided cost for a given technology and project size. The Commission can determine, through a staff proposal informed by comments by parties, the cost, including reasonable profit, for projects of varying technologies and sizes. Procedurally, this is a similar process that the Commission has used to set the MPR, which is similar to the process used by the California Energy Commission (―CEC‖) to establish the Levelized Cost of Energy (―LCOE‖) of various technologies as in its most recent report, ―Comparative Costs of California

Central Station Electricity Generation; January 2010.‖[18] As with these report, there are a number of consulting firms that have the experience and capacity to assist the Commission in setting these rates including KEMA, Aspen, E3, Black & Veatch, Navigant and others. Several of these firms have presented research to the CEC and the Commission regarding the costs of varying technologies and prices. We recommend that these tariffs be set for two years and for the Commission to revisit these tariffs at least every two years. Since solar PV is the technology with the rapidly changing (decreasing) costs, it is recommended that the solar PV tariffs be set with a built in digression price such as 5% per year if the Commission finds, based on solar PV industry trends, that such a digression rate is reasonable and projected to occur.

Sierra Club California recommends that the PUC include at least solar PV, wind, biogas, biomass and geothermal technologies but are open to including all California eligible renewable technologies. Tariffs should be further differentiated by appropriate project sizes within each technology type, based on natural price breaks in size or application. Please refer to Question 1, Section B for details on differentiation by technology and size.

All of the renewable technologies referenced in the above paragraphs should have at least a 20 year contract term to lower the annual rate costs to ratepayers.

A portfolio of renewable technologies of various project sizes will keep the weighted average costs of energy low. This is because the majority of KWh of energy will come from the relatively larger projects at lower costs thus offsetting the somewhat higher costs of smaller projects.

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.

[18] CEC-200-2009-07SF.

See responses to Questions 1 and 6. In addition, the CPUC could use the costs of similar projects contracted for under the RPS solicitation process, IOU PV solar programs, RAM and other national and international sources of data to validate tariff calculations before finalizing.

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.

See response to Question 7.

3.3.2 Market-Based Rate

9. 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.

We do not support a competitive auction for this program, as the Commission has already established such a program in the Renewable Auction Mechanism (―RAM‖). While a market-based rate is one potential option that could result in lower costs due to the use of competitive auction, this will impose uncertainty and transaction costs, and disadvantage smaller projects.

SB 32 and SB 2 1X established a feed-in tariff program based on a generator's certainty of the price, and the standard contract that would be offered for producing renewable energy. The RAM program offers benefits to the state, and setting a 20 MW project size cap is a positive feature of this program, which Sierra Club California also recommends for the Section 399.20 program. However, the RAM is biased towards larger DG projects to the detriment of smaller projects. It is unlikely that smaller projects would seek to participate in the RAM program even though such sized projects offer many benefits to the state.

Further, it is possible that Sierra Club California's proposals for the tariff structure for the Section 399.20 program will result in lower costs of generation than similar type and sized projects under the RAM program. This is because feed-in tariff programs include long-term, simple, standardized, and must-take contracts, set at a cost + reasonable profit price. With these features and expedited interconnection, a successful feed-in tariff program can lower the costs of a project by lowering the costs of financing and transacting when compared to competitive bidding programs. It would be beneficial to the state to continue to compare these two mechanisms to see which produces the most new renewable generation quickly, at what cost, and the relative value of potential differences in typical project technologies and sizes. One or both of these programs may prove their effectiveness as California increases its renewable energy portfolio.

Additionally, one risk of the RAM program is that successful bidders could bid too low, resulting in projects that are delayed or never get built – often from over failure to get financing at reasonable rates. Such deliverability problems have been observed in the implementation of contracted projects from RPS solicitations. Therefore, a parallel program that relies on a technology-specific price that has the benefit of certainty and reduced transaction and financing costs for developers is likely to result in the increased viability of smaller projects, less expensive costs for similar projects and a much higher project completion rate.

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 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.

Please see responses to Questions 3, which discusses the disadvantages of continued reliance on the MPR. A market price based on power purchase agreements would be unlikely to yield a tariff rate sufficient to encourage several technologies and smaller projects. This is because RPS solicitations are based on a different pool of resources that range into utility scale projects. Therefore, it is inappropriate to set a rate based primarily on RPS bid solicitation power purchase agreements.

However, a Commission investigation may find that power purchase agreements that are specific to comparable technologies and project sizes may assist the Commission's investigation to determine technology-specific costs and prices. The Commission should take into consideration the scale of developers using PPAs for multiple projects with regard to transaction and financing costs.

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

Sierra Club California recommends a pricing proposal for market price to be set as avoided cost, inclusive of line items within the MPR, time of delivery, and locational benefits of avoided cost of transmission and distribution. The Commission should establish procurement targets so that avoided cost may be set to be commensurate to the cost of developing specific technologies and project sizes to promote a balanced portfolio and cost-effectiveness.

The Commission may choose to consider alternate mechanisms proposed by parties. In such an event, Sierra Club California suggests that use of Renewable Energy Credit (REC) value could be a potential option for supplementing market price in a way that does not conflict with PURPA. Additionally, if the Commission does not establish procurement targets to allow for avoided cost to be set based on technology-specific and size-specific characteristics, Sierra Club California recommends a cost-containment mechanism that would limit tariffs to the reasonable cost and profit of developing a specific renewable technology and project size.

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.

It is very important for data used for ratemaking to be available to the public. Data used to derive the rates should at a minimum be made available to parties to a proceeding so there is opportunity to review and comment on ratemaking. The Commission should conduct an independent investigation of the Fuel Cell Energy and CALSEIA data sources, but it is appropriate to use such sources as a starting point, particularly with regard to the research conducted on locational benefits.

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.

Please see response to Question 5.

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.

Sierra Club California concurs with the recommendations of CEERT, Clean Coalition, and CALSEIA regarding the interpretation of ratepayer indifference. In the AB 1613 feed-in tariff Decision, the Commission held that ratepayers would be indifferent to a Combined Heat and Power tariff that included environmental and locational benefits along with the market price of power.[19] Further, market prices that are equivalent to avoided costs are by definition qualifying as ratepayer indifferent, because a ratepayer would pay an equivalent avoided cost but for the feed-in tariff program.

3.6 FERC Order 134 FERC 61,044 – Order Denying Rehearing

15. Please indicate how the positions set forth in the March 2011 briefs have changed, if at all.

Please refer to our responses to Questions 1 and 2 on the substantive implications of the recent FERC rulings, which support the rationale for Commission adoption of defining market

[19] D.09-12-042 at 17.

price as avoided cost. Sierra Club California's position on the appropriate use of avoided cost of differentiated technologies has not changed, but the FERC rulings clarify the appropriate legal form for achieving this goal.

4 Compliance with SB 32

16. Parties are requested to comment on this proposal to implement selected provisions in 2011 and in 2012.

Sierra Club California supports the recommendation with respect to which sections of 399.20 should be finalized by the end of 2011 and which deferred until 2012 with one exception and one clarification. We believe that the cost allocation of interconnection, which affects pricing, should be addressed and resolved in 2011. Other interconnection-related barriers should be addressed as soon as possible.

Sierra Club California supports developing the pricing structure and finalizing the standard contracts and tariffs as soon as possible. If the pricing structure as proposed cannot be resolved in 2011, Sierra Club California would recommend an interim decision that achieves the best feasible pricing structure, followed by additional development of a well-designed structure in 2012.

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.

Sierra Club California stated in Opening Briefs in March 2011 that the CPUC should use its authority to implement a program effectively increasing the project capacity limitation to 20 MW, as the Commission has done in the RAM program. The Commission may do this immediately, or as part of issues to be considered in 2012.

Alternately, the Commission should increase the program size cap to nameplate capacity of 5 – 15 MW in the tariffs approved in 2011 to account for the difference between effective capacity and nameplate capacity. The statute defining a project capacity limit refers to—an effective capacity,‖ of 3 MW as opposed to a nameplate capacity.[20] This would offer the benefit of allowing a large portion of the projects to be larger at a lower cost due to economies of scale and thus lowering the weighted average total costs per KWh under this program to ratepayers. The Commission should investigate the expected effective capacities for eligible technologies, particular the resources with lower effective capacities such as solar and wind, and adjust the capacity limit to allow equivalent nameplate capacity projects access to the program. For example, if the Commission finds that solar PV has a typical capacity factor of 25%, then the nameplate capacity limit for solar PV should be expanded from 3 MW effective capacity to 12 MW nameplate capacity.

[20] Public Utilities Code § 399.20(b)(1).

4.2 Proportionate Share and Increased Program Cap to 750 MW

Sierra Club California recommends that in establishing the increased program cap of 750 MW, for the Commission to establish this SB 32 program and capacity limit independent of completed projects pursuant to AB 1969. The Commission retains the discretion to implement renewable energy policies, and without establishing this capacity limit independently, the queue for preexisting AB 1969 projects may soon fully subscribe the SB 32 program.

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?

As stated in our opening briefs, Sierra Club California would support increasing the obligation shared by the Investor Owned Utilities to 750 MW, or well beyond this to help support the Governor's proposed goal of 12,000 MW of distributed renewable energy by 2020, a goal which Sierra Club California supports. This allocation would not reduce the feed-in tariff procurement obligations of the municipal utilities under this program.

4.3 Separate Tariffs

19. This ruling proposes to implement consolidated tariffs by end of 2011. Explain the steps necessary to implement this request.

We support the ALJ recommendation to consolidate the two rate schedules into one, provided that the actual rates are differentiated by technology.

4.4 Retail Customer Requirement Eliminated

20. 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.

Sierra Club California supports eliminating the Retail Customer requirement.

4.5 Yearly Inspection and Maintenance Report

21. Parties are asked to comment on this recommendation to implement this change in 2012.

Sierra Club California supports addressing this issue in 2012.

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

22. Parties are asked to comment on the recommendation to implement in 2011.

No comment.

4.7 Publicly owned electric utilities

23. 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.

No comment at this time.

4.8 Utility Discretion to Deny Tariff

24. Parties are asked to comment on this recommendation. Also, explain the existing procedure relied upon by electric utilities to deny tariff requests.

As stated in our Opening Brief, Sierra Club California believes that utilities should not be allowed to deny the tariff on any other ground than failure of the project to meet the objective standards approved by the Commission, and whether the project can reasonably and safely connect to the distribution grid. The utility should have minimal discretion or discrimination in making these factual findings for denial. The intent of the feed-in tariff legislation is to promote renewable distributed generation (―RDG‖) as a strategy to help the state achieve its RPS targets. In order to accommodate these new generation projects, it is in the interest of ratepayers and the state that electrical corporations upgrade their distribution grids to accommodate more RDG in priority areas such as industrial parks where existing DG grids and substation transformers may not have sufficient reserve capacity. Just as utilities build and pay for approved new transmission to support large scale projects to benefit their customers, they should upgrade their distribution grids in order to support distributed generation.

In summary, the commission should generally require utilities to cooperate with developers, facilitate implementation of this program, and not become a barrier to its success. Utilities should be constrained to making decisions based upon objective criteria rather than discretion, and the commission should enforce this requirement. Developers should have the right of appeal to the commission if they are denied, or to resolve other conflicts, and should be encouraged to report any problems to the commission.

4.9 Tariff or Contract Termination Provisions

25. Parties are asked to comment on this recommendation. Also, explain the existing procedure relied upon by electric utilities to terminate contracts.

No comment.

4.10 Expedited Interconnection Procedures

26. Parties are asked to comment on this recommendation.

Sierra Club strongly supports efforts to rationalize and expedite the interconnection process. This has long been recognized as one of the major barriers to distributed generation. The commission should investigate utility practices that achieve rapid interconnection, and require the electrical corporations to implement them. If more staff is required to process large volumes of requests, then the commission should work with the utilities to insure adequate staff and other resources are devoted to this process.

A key component of interconnection issues that must be addressed in 2011 concurrent with price setting is the allocation of interconnection costs. Interconnection costs are often significant barriers to integration of renewable distributed generation. An example of where this barrier has been overcome is in Germany, where the utility assumes cost responsibility for interconnection, and the costs are included in the rate base. Alternatively, the Commission could develop another mechanism for the standard tariff to reimburse interconnection costs for differentiated technologies.

In a memo to the California Energy Commission, KEMA recognized interconnection costs as a serious issue in a recent study comparing interconnection infrastructure in Germany and Spain.[21] Their study included in its findings that―It is possible that selective changes to rate-making design and capital cost allocation policies in California related to integration of DG into the distribution and transmission grids could incentivize a higher rate of DG growth in California.‖[22]

[21] ―Distributed Generation in Europe – Physical Infrastructure and Distributed Generation Connection,‖ KEMA, Inc. April 29, 2011.
[22] Id at 53.

Sierra Club California recommends that additional costs associated with upgrade of the distribution circuit, transformer, or protective devices be covered by the utility in the rate base. The current practice is to have generators bear these costs, however these costs cause barriers at the point that they are charged, but ultimately are absorbed into the rate base. By including these cost upfront in the rate base, it creates a fair and level playing field for developers while promoting the more rapid implementation of DG renewables, removing a very significant barrier. In addition, the current practice is inherently unfair in that the first in developer bears a disproportionate share of cost of the DG upgrades benefitting subsequent generators using the same circuit. Time to negotiate upgrade costs with the IOUs is one of the major causes of interconnection delays and hence one of the biggest barriers to interconnection that exist today. Expediting interconnection procedures requires removing this barrier by rate basing these costs. As each utility is currently working to develop and implement its smart grid deployment plan, many circuits will need to be upgraded anyway so the only issue is one of timing and not ultimately one of significant costs.

4.11 Adjustments for Small Electric Utilities

27. Parties are asked to comment on this recommendation.

No comment.

4.12 Refunds of Other Incentives

28. Parties are asked to comment on this recommendation.

Please see Sierra Club California's comments in our Opening Brief. Sierra Club California agrees that incentive programs should be coordinated to avoid windfall profits or double-counted environmental benefits.

5. Administrative and Procedural Issues

Sierra Club California urges the Commission to take a leading role in investigating methodologies and data sources recommended by Sierra Club California and other parties, and assisting with fact-finding to develop the feed-in tariff program by the end of 2011. This investigation is needed particularly for identifying the avoided cost of differentiated technologies, the cost of interconnection, and locational benefits of avoided transmission and distribution costs. Sierra Club California would support the use of alternative dispute resolution negotiation tracks and workshops to settle pricing issues and the allocation of capacity for specific technologies to allow for the Commission to arrive at an expedited Decision, rather than evidentiary hearings. If necessary, workshops can include portions that are on the record for the receipt of exhibits and discovery interrogatories. However, lengthy evidentiary hearings are likely to cause a significant delay in implementation. Finally, due to the expedited timeline, Sierra Club California respectfully recommends for the Commission to encourage in reply comments and workshops the presentation of additional data and quantitative models that support the methodologies that Parties articulate in opening comments, for discussion at the scheduled workshop, or future comments on a staff proposal or proposed decision.

Respectfully submitted,

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Dated: July 21, 2011

VERIFICATION

I am the Senior Advocate with Sierra Club California and am authorized to make this verification on its behalf. I am informed and believe that the matters stated in this pleading are true.

I declare under penalty of perjury that the matters stated in this pleading are true and correct.

Executed on the **21st day of July, 2011**, at Sacramento, California.

/s/ Jim Metropulos

____

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